OPTIMIZATION OF FRACTURED WELL PERFORMANCE OF HORIZONTAL GAS WELLS

A Thesis

by

FELLIPE VIEIRA MAGALHÃES

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

August 2007

Major Subject: Petroleum Engineering

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Approved by:

Chair of Committee, Ding Zhu
Committee Members, Peter P. Valko
Paulo Lima-Filho
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ABSTRACT

Optimization of Fractured Well Performance of
Horizontal Gas Wells. (August 2007)
Fellipe Vieira Magalhães, B.S., Texas A&M University
Chair of Advisory Committee: Dr. Ding Zhu

In low-permeability gas reservoirs, horizontal wells have been used to increase the reservoir contact area, and hydraulic fracturing has been further extending the contact between wellbores and reservoirs. This thesis presents an approach to evaluate horizontal well performance for fractured or unfractured gas wells and a sensitivity study of gas well performance in a low permeability formation. A newly developed Distributed Volumetric Sources (DVS) method was used to calculate dimensionless productivity index for a defined source in a box-shaped domain. The unique features of the DVS method are that it can be applied to transient flow and pseudo-steady state flow with a smooth transition between the boundary conditions.

In this study, I conducted well performance studies by applying the DVS method to typical tight sandstone gas wells in the US basins. The objective is to determine the best practice to produce horizontal gas wells. For fractured wells, well performance of a single fracture and multiple fractures are compared, and the effect of the number of fractures on productivity of the well is presented based on the well productivity.

The results from this study show that every basin has a unique ideal set of fracture number and fracture length. Permeability plays an important role on dictating the location and the dimension of the fractures. This study indicated that in order to achieve optimum production, the lower the permeability of the formation, the higher the number of fractures.

DEDICATION

This work is dedicated:

To my parents who have taught and still teach me everything I need to know in order to be a good person. Without them I would be nothing.

To my two lovely grandmothers who cheer me up with their presence and memories.

To my sister who always supported me.

To my cousins who stepped out of their way so that they could give me a good time when I went back to visit.

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Thanks to God for blessing me with a lot more than I could ever wish for.

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I would like to thank Dr. Ding Zhu for her endless support in achieving this degree. I would also like to thank her for her continuous effort to make her students feel happy and welcome at her office and at her home.

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Lastly, thanks for all my colleagues and friends who have shared their time and knowledge with me: Gina Melendez, Eduardo Jimenez, Toby Rice, Johan Daal, Keita Yoshioka, Jassim Almulla, Abdullatif Al-Omair, Terje Aarthun, Varun Mishra, Sandeep Kaul, Luis Antelo, Omer Izgec and Adedayo Adebamiro.

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CHAPTER I
INTRODUCTION

Oil and Gas production from conventional reservoirs has reached its peak. The oil and gas industry is, on the other hand, on the rise. The industry is desperately in need of new man power and new technology. Technology is needed to develop unconventional resources. Unconventional resources can be defined as reservoirs that cannot be produced at economic flow rates or that do not produce economic volumes of oil and gas without the assistance from massive stimulation treatments or special recovery processes and technologies. Tight gas sands, coal bed methane, gas hydrate deposits, heavy oil, tar sands and shale gas are the main targets for the next generation of petroleum engineers. Many of these resources are being explored but current technology poses a limit to high production rates, which explains the need for research in this area.

Development of low permeability tight gas reservoirs, commonly known as tight gas, is one of the solutions to today's energy supply and demand problem. The lack of a flow path for the gas is the biggest limitation for tight gas formations. In order to overcome that limitation, horizontal wells have been drilled, and furthermore, hydraulically fractured. Hydraulic fracturing is probably the most commonly used method used nowadays to expand the contact between the well and the formation.

For horizontal wells, drilled in low permeability formations well performance becomes very sensitive to permeability and anisotropic ratio. This applies for both fractured and non-fractured horizontal wells. If the vertical permeability is the formation is extreme low (high anisotropic ratio) the benefit of non-fractured horizontal wells starts diminishing. In such cases, hydraulic fracturing provides another option to increase well

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This thesis follows the style of *SPE Journal* contact with the reservoir and therefore productivity as well. When hydraulically fracturing a horizontal well, created fractures can be: longitudinal, single or multiple transverse. The orientation and placement of fractures along a horizontal well greatly affect the performance of the well. Predicting well performance for fractured and non-fractured horizontal wells can help to achieving higher production from low permeability gas formations.

1.1 Literature Review

Horizontal well models have been presented in the past literature. In order to arrive at an analytical solution, many boundary conditions had to be assumed. Models for steady-state flow, when the pressure is maintained constant at the boundaries of the reservoir, have been developed by Butler (2000)[1]; Furui, Zhu and Hill (2003)[2]; and Kamkom and Zhu (2006)[3]. Furui, Zhu and Hill developed a model that was based on the superposition of pressure drop in the reservoir from a radial flow region (near the well) and a linear region (far field). This model also considered the effect of anisotropy ratio and damage heterogeneity. Babu and Odeh (1988 and 1989)[4-5] developed a model for pseudo-steady state, where the reservoir is being depleted, and there is no flow across the boundary. This model also introduced a widely used partial penetration skin for horizontal wells. Ozkan (1988)[6] and Ozkan, Sarica, and Haciislamoglu (1995)[7] developed a model for transient flow, where the boundary in not yet reached. It is very common for tight gas formations to flow under transient condition, as the ones that are going to be studied in this thesis. Further more, Kamkom and Zhu (2006) applied steady state and pseudo steady models to different types of fluids, including gas wells.

Finally, models were then developed for horizontal wells with fractures. Daal and Economides (2006)[8] presented a model combining a productivity index with a fracture skin. This model divided the productivity from each fractures into different drainage areas. It also allowed calculating the optimum fracture height, width and length based on the number of fractures desired.

1.2 Objectives

The objectives of this study is to predict gas well performance in tight sand formations, to evaluate the critical parameters, such as permeability and anisotropic ratio, well trajectory and drainage size on well productivity, and therefore to optimize well and fracture treatment design. A newly developed Distributed Volumetric Source (DVS) method by Amini and Valko (2007)[9] will be used to predict the performance of gas wells with or without fractures. This method solves the flow problem in a box-shaped reservoir with a volumetric source. The shape of the source can be changed in many ways, portraying a horizontal well with or without fractures. There is a smooth transition between transient and pseudo steady state flow regions. This method is flexible to multiple fractures, different drainage areas, fracture geometries and fracture orientation. The model provides a dimensionless productivity index, which ca be easily converted into production rate.

Using the DVS method the objective to determine the best practice to produce horizontal gas wells will be achieved. With the transient flow feature of the DVS method, well placement for multiple horizontal wells in a defined drainage area can be studied, and the limit of well spacing is identified. For fractured wells, well performance of a single fracture and multiple fractures are compared, and the effect of the number of fractures on productivity of the well is presented based on the well productivity. Realizing that reservoir permeability and anisotropy ratio are the critical parameters in developing low-permeability gas field, the effect of permeability on well performance, well placement and fracture treatment design is also addressed.

The well performance is represented by a dimensionless productivity, J_D. The DVS method is used to calculate J_D for different systems. For multiple fractures, the superposition principle is applied to the multiple sources in the system. Wellbore pressure distribution caused by flow into the wellbore from the fractures is defined by coupling the fracture flow with wellbore hydrodynamics. Finally, material balance is used to predict pressure decline once reached the pseudo-steady state condition.

CHAPTER II
METHODOLOGY

The Distributed Volume Sources (DVS) model predicts the pressure/flow response of a box shaped domain with a volume source υ placed anywhere inside. Fig. 2.1 shows the schematics of a typical DVS system. One dimension flow problem is first solved, and the 3D problem's solution is the product of three 1 dimension solutions. It provides a dimensionless productivity, J_D, defined as the flow over unit pressure difference. At very early times, J_D gives very high values, and it decreases to a steady decline until it stabilizes. This period of decline is known as transient state flow. When it stabilizes the well has undergone pseudo-steady or steady state flow. When this type of flow is reached, material balance is used to calculate the average reservoir pressure decline for the pseudo steady state flow condition.

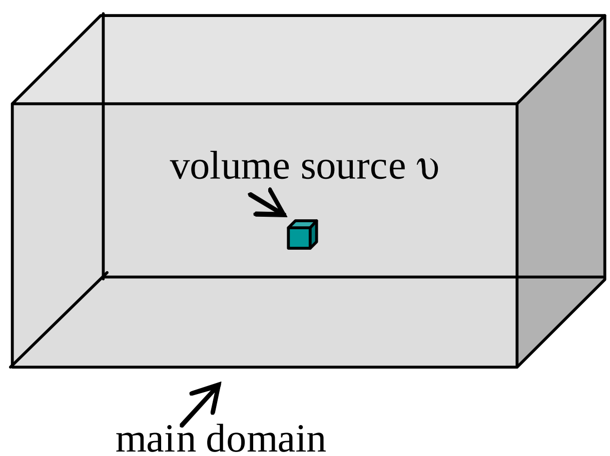


Fig. 2.1 Illustration of the DVS method

The DVS method is based on the Newman principle that generates the solution of a three-dimensional from the product of the solutions of three one-dimensional problems. With volumetric source, it eliminates any singularity in the flow problem. One of the main advantages of using this method is that it presents a smooth transition from transient flow regime to pseudo-steady state regime. The details of the model are discussed by Amini and Valko. The dimensionless productivity index, J_D, by definition, is

$$J_D = C_1 \frac{q}{\Delta p} \tag{1}$$

Where the constant C in Eq. 1, in the field units, is

$$C_1 = \frac{1424 \cdot \beta\mu}{kh} \tag{2}$$

For gas wells, β is gas formation volume factor, it can be expressed in terms of temperature and pressure as:

$$\beta_g = \frac{\frac{znRT}{P}}{\frac{z_{sc}nRT_{sc}}{P_{sc}}} \tag{3}$$

Where, P_{sc}, T_{sc}, z_{sc}, are pressure, temperature and compressibility index at standard conditions (14.7 psi, 520°R, and 1 respectively). The variables, n and R, which stand for number of moles and gas constant are canceled out in the equation. The pressure value is equal to the average of the reservoir and flowing pressures. With all these variables J_D becomes:

$$J_D = C_2 \frac{q}{\left(P_{re}^2 - P_{wf}^2\right)} \tag{4}$$

Where the constant C_2, in oil field units is:

$$C_2 = \frac{1424 \cdot \overline{Z\mu T}}{kh} \tag{5}$$

The gas properties z and μ are evaluated at the average pressure and temperature. Furthermore, the pseudo pressure function can be calculate the productivity of a gas well. The pseudo pressure is defined as:

$$m(p) = 2\int_{P_{wf}}^{P_{re}} \frac{P}{\mu q z}\, dp \tag{6}$$

Thus J_D can be written as:

$$J_D = C_3 \frac{q}{m(P_{re}) - m(P_{wf})} \tag{7}$$

And:

$$C_3 = \frac{1424T}{kh} \tag{8}$$

To apply this method for horizontal wells with or without fractures, we define the source term (the location of the source and the geometry dimensions) and the main domain according to each individual physical system. The reference permeability, k, in Eq. 2 is different for horizontal wells with or without fractures, and this will be addressed individually in the following sections.

2.1 Horizontal Well

For a horizontal well located in a box-shaped reservoir, the well itself can be simply treated as one source, as shown in Fig. 2.2. The length of the source is equal to the horizontal well length, the cross-section area of the source, A_s, is equivalent to the wellbore cross-section area,

$$A_S = \pi \cdot r_w^2 \tag{9}$$

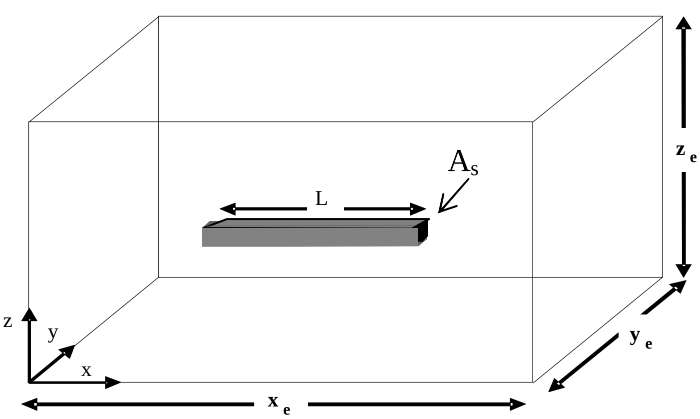


Fig. 2.2 DVS representation of a horizontal well

For a horizontal well, if we assume that anisotropy is only in vertical and not horizontal direction ($k_x = k_y = k_H$), then the reference permeability

$$k = \sqrt{k_h \cdot k_v} \tag{10}$$

is used to calculate the constants C_1, C_2 and C_3 in Eqs. 2, 5, and 8 respectively. This assumption is present in all of the examples and case studies throughout this thesis. In case of three dimensional anisotropy,

$$k = \sqrt[3]{k_x \cdot k_y \cdot k_z} \tag{11}$$

2.1.1 Example of Horizontal Well Performance Calculation

The example in this section will also be use to validate the DVS method for well performance. Once confirmed, the method is used to evaluate the performance for horizontal wells, horizontal wells with longitudinal fractures, or transverse fractures. The results of DVS method are compared with the analytical solution by the Babu and Odeh[4-5] model. Since the Babu and Odeh's model is for pseudo-steady state conditions, we only compared the result in the pseudo-steady state time range. Material balance is used to calculate pressure decline for the Babu and Odeh method. The input data for this validation process is given in Table 2.1. This data is going to be used in every synthetic example mentioned on this thesis. The comparison is shown in Fig. 2.3. The result is satisfying with a difference between the two methods of only 0.37%.

Table 2.1 Validation input data		
Horizontal Well Length	1000	Ft
Well Radius	0.3	Ft
Drainage Area	80	Acres
Net Pay Thickness	100	Ft
Fluid Viscosity	0.0244	Cp
Reservoir Temperature	180	^oF
Reservoir Pressure	4350	Psi
Horizontal Permeability	0.1	Md
Vertical Permeability	0.01	Md
Compressibility Factor	0.945	
Gas Gravity	0.71	
Wellbore Flowing Pressure	900	Psi
Formation Porosity	0.05	
Total Compressibility	1.3E-05	psi^{-1}
Formation Volume Factor	0.0371	scf/bbl

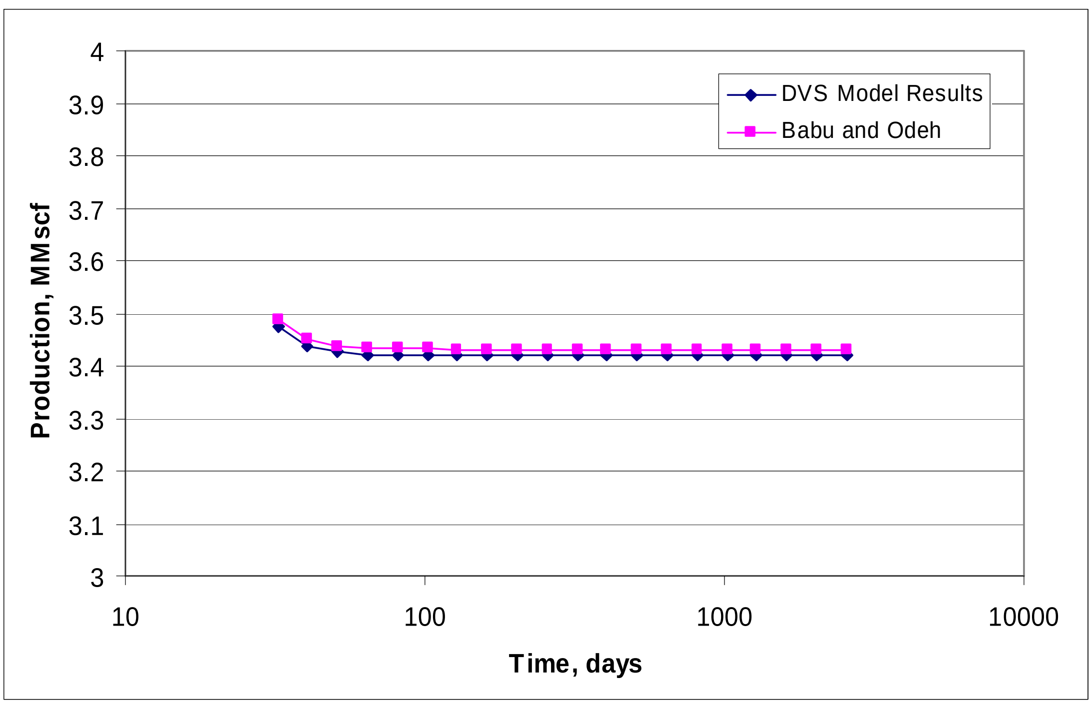


Fig. 2.3 Comparison of DVS method with analytical solution

2.2 Horizontal Well with Longitudinal Fracture

A schematic of longitudinal fracture along a horizontal well is illustrated in Fig. 2.4. If the fracture has infinite conductivity, or uniform flux, the fracture itself can be treated as one source in the system.

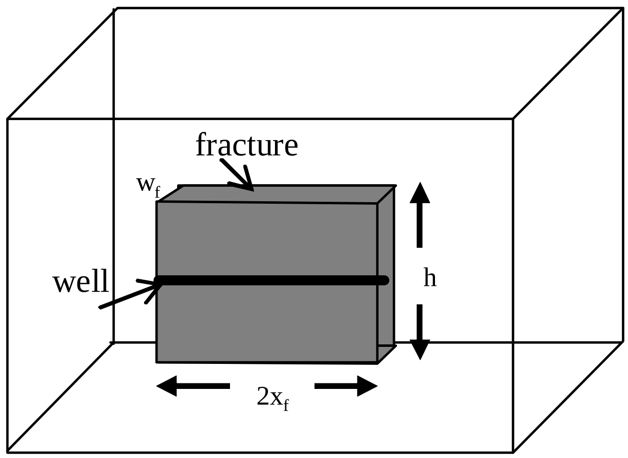


Fig. 2.4 DVS representation of a longitudinal fracture

To use the DVS method, the fracture does not have to fully penetrate the formation. In this case, the source length can be the fracture length, and cross sectional area of the source is defined as

$$A_S = wh_f \tag{12}$$

Where w is the fracture width and h_f is the fracture height. Since the dominated flow to the longitudinal fracture is more likely perpendicular to the fracture, horizontal permeability, k_H is used as the reference permeability in Eqs. 2, 5, and 8.

The inflow to the horizontal well is neglected compared with the flow into the fractures in this study. This assumption is appropriate if the fracture length is close to the horizontal well length. If the longitudinal fracture is significantly shorter than the wellbore, then the inflow into the wellbore should also be considered.

2.2.1 Example of Horizontal Well with Longitudinal Fracture Calculation

Using the same data as Table 2.1, an example calculation of a longitudinal fractured that is along the entire length of the horizontal well is demonstrated. This fracture will be fully penetrating on the z-direction and with a width of 0.5 inches. The results from this demonstration are shown in Fig. 2.5.

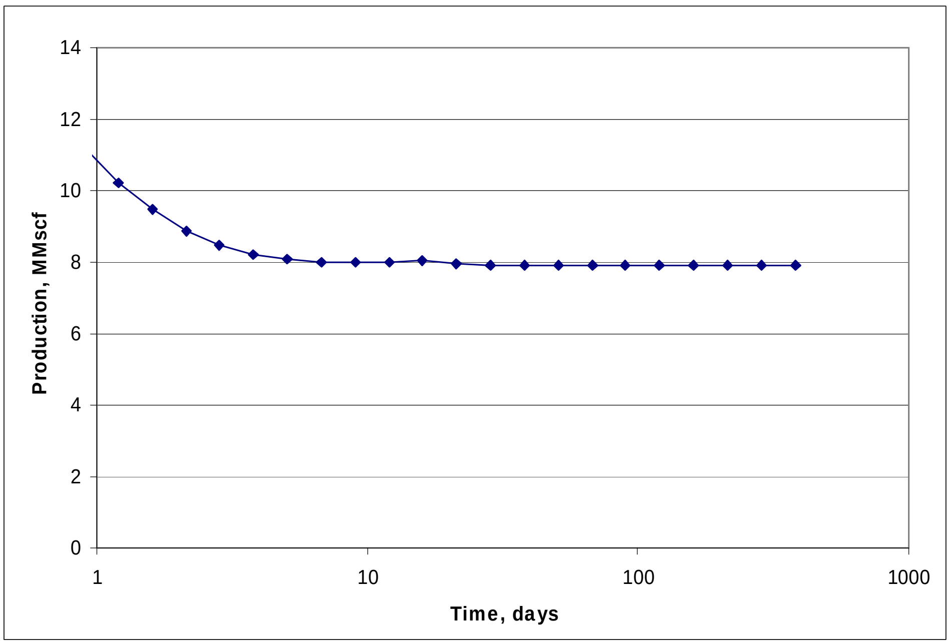


Fig. 2.5 Example of horizontal well with longitudinal fracture performance

2.3 Horizontal Well with Transverse Fractures

Fig. 2.6 shows an example of multiple transverse fracture case. If there is only one transverse fracture along a horizontal well, and if the fracture is infinitely conductive or with uniform flux, the fracture can still be treated as one source, under the assumption that the fracture is dominating the total production to the well.

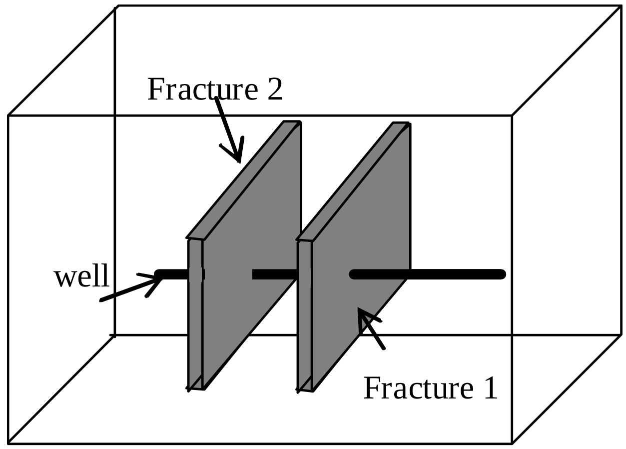


Fig. 2.6 DVS representation of transverse fractures

If multiple fractures are intersecting with the horizontal well, which is more likely the situation, and we assume that all the production is coming from the fractures (cased and perforated well), then each fracture can be treated as an individual source and their effects to other fractures are included through superposed pressure drawdown,

$$P_{re} - P_{wfi,j} = \sum_{j=1,N} \frac{J_{Di,j}}{q_{D,j}} \tag{13}$$

The first subscript of the productivity index in Eq. 13 denotes the fracture that causes the pressure change, and the second subscript denotes the location that observes the pressure change. If considering pressure drop in the wellbore between fractures,

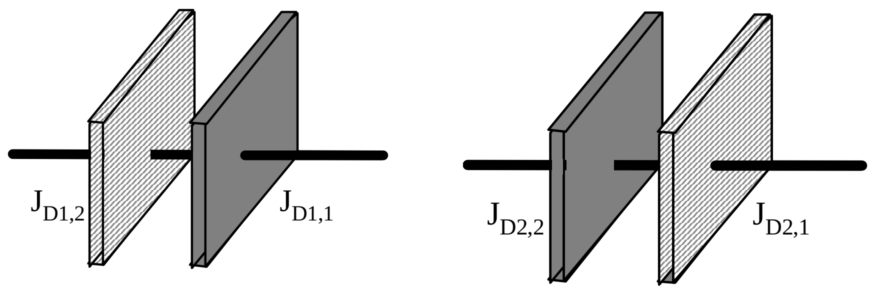
$$P_{wf,i} - P_{wf,i-1} = \Delta p_{wellbore,i} \tag{14}$$

For a constant rate constraint and the calculation of dimensionless numbers, the total rate from all of the fractures is:

$$q_{D,t} = \sum_{i=1,N} q_{D,i} = 1 \tag{15}$$

$J_{Di,j}$ in Eq. 13 is calculated by the DVS method, there are 2N unknowns ($q_{i=1,N}$ and $p_{wf,i=1,N}$) in the system. Eq. 13 provides N equations at each fracture location (N observation points); Eq. 14 supplies N-1 equations (N-1 wellbore sections between each pair of conjunct fractures), and Eq. 15 adds one more to a set of 2N equations to solve for the unknowns.

Fig. 2.7 shows an example of productivity calculation for a 2-fracture case. To calculate the well performance, we first let only the fracture 1 exists in the system, which causes a flow rate of q_1 at the location of the fracture 1. This flow results in corresponding pressure changes at both locations of the fracture 1 ($\Delta p_{1,1}$) and the fracture 2 ($\Delta p_{2,1}$).



Only fracture 1 exists Only fracture 2 exists

Fig. 2.7 Productivity calculation for two transverse fractures

The dimensionless productivity indexes, $J_{D1,1}$ and $J_{D1,2}$ are related to the flow rate and pressure drops as

$$\Delta p_{1,1} = \frac{J_{D1,1}}{q_1} \tag{16}$$

$$\Delta p_{2,1} = \frac{J_{D1,2}}{q_1} \tag{17}$$

Similarly, if we only let the fracture 2 exists that produces a flow rate of q_2, then the pressure changes caused by this flow will be $\Delta p_{1,2}$ at the location of the fracture 1, and $\Delta p_{2,2}$ at the location of the fracture 2. This gives us

$$\Delta p_{1,2} = \frac{J_{D2,1}}{q_2} \tag{18}$$

and

$$\Delta p_{2,2} = \frac{J_{D2,2}}{q_2} \tag{19}$$

By the superposition principle, the total pressure drawdown at each location should be the sum of pressure drops caused by all the fractures in the system, thus we have

$$P_{re} - P_{wf,1} = \Delta p_{1,1} + \Delta p_{2,1} = \frac{J_{D1,1}}{q_1} + \frac{J_{D2,1}}{q_2} \tag{20}$$

and

$$P_{re} - P_{wf,2} = \Delta p_{2,1} + \Delta p_{2,2} = \frac{J_{D2,1}}{q_1} + \frac{J_{D2,2}}{q_2} \tag{21}$$

The pressure drop inside the wellbore relates the wellbore flowing pressure $p_{wf,1}$ and $p_{wf,2}$[11]

$$P_{wf,2}^2 = p_{wf,1}^2 - 1.007 \cdot 10^{-4} \frac{\gamma_g f_f \overline{ZT} q_1^2 L}{D^5} \tag{22}$$

Finally, the total flow rate from the well will be

$$q_t = q_1 + q_2 = 1 \tag{23}$$

Eqs. 20-23 provide the solution for q_1, q_2, p_{wf1}, and p_{wf2} and can be summarized as

$$J_{D,global} = \frac{1}{\Delta P_{f,global}} \tag{24}$$

2.3.1 Horizontal Well with Transverse Fractures Performance Calculation

As noticed in this section, the calculation for this type of fracture is more complex than the previous ones. The reason for that is that superposition of fractures is used, which adds more calculations to the final J_D. The same data from Table 2.1 is used here to show the results from this experiment. The 2 fractures are placed similarly to Fig. 2.6. The first one is placed at 622-ft on the x-axis from the right boundary and the second fracture is placed 1245-ft off the right boundary. They are placed strategically at 1 and 2 thirds of the total reservoir length on the x-axis so that they will both drain the reservoir equally.

The following calculation will show how to calculate the J_D from at one point in time. The output from the calculations was the following: $J_{D1,1}$ = 2.3, $J_{D2,2}$ = 2.3, $J_{D1,2}$ = 1.2, $J_{D2,1}$ = 1.2. These results were obtained by running the program for each individual fracture. Since the fractures are symmetrically placed in the reservoir, it is easy to notice that each will produce half of the total well production. From Eqs. 10, 11, 12 and 13 it is obtained:

$$\Delta p_{1,1} = \frac{J_{D1,1}}{q_1} = \frac{2.3}{0.5} = 4.6$$

$$\Delta p_{2,1} = \frac{J_{D1,2}}{q_1} = \frac{1.2}{0.5} = 2.4$$

$$\Delta p_{1,2} = \frac{J_{D2,1}}{q_2} = \frac{1.2}{0.5} = 2.4$$

$$\Delta p_{2,2} = \frac{J_{D2,2}}{q_2} = \frac{2.3}{0.5} = 4.6$$

To simplify the calculations, it is assumed that the pressure drop inside the wellbore is too small compared to the drawdown, and therefore ignored. With this assumption, Eqs. 14 and 15 will give the same result as shown next:

$$P_{re} - P_{wf,1} = \Delta p_{1,1} + \Delta p_{2,1} = \frac{J_{D1,1}}{q_1} + \frac{J_{D2,1}}{q_2} = 4.6 + 2.4 = 7$$

$$P_{re} - P_{wf,2} = \Delta p_{2,1} + \Delta p_{2,2} = \frac{J_{D2,1}}{q_1} + \frac{J_{D2,2}}{q_2} = 4.6 + 2.4 = 7$$

According to Eq. 18 it is obtained:

$$J_{D,global} = \frac{1}{\Delta P_{f,global}} = \frac{1}{7} = 3.5$$

This result makes sense because it corresponds to almost the double of the J_D from one fracture, which is 2.3.

The method was implemented to an Excel program with J_D calculated by Mathmatica®. The description of the program is shown in Appendix A. Appendix B, shows the description of the Excel spreadsheet that converts the dimensionless to variables used in the oilfield.

CHAPTER III

RESULTS AND DISCUSSION

Using the method introduced in chapter II, we carried out a study of gas well performance in tight sand formations with or without fractures. The main target of this thesis is low permeability formations, and the results are not limited to a certain range of reservoir permeability. In each presented case, a production history is generated and then the parameter that is of interest to the well performance is varied. Under different conditions, the well performances are compared, and the optimal design of well structure or fracture geometry is identified. The sensitivity of well performance to permeability and anisotropy ratio is examined.

Four different basins were selected to conduct this study. Each was chosen to study a different parameter. Appalachian basin has undergone extensive development in the recent years, therefore requiring more exact predictions on the performances of the wells. Several infill wells have been drilled to take better advantage of the drainage area. Well spacing and horizontal well length study were based on the data from this basin. The second field used in the study is the data from the East Texas basin. About one third of all the wells in the Travis Peak formation in East Texas basin are gas wells. It was estimated that the Travis Peak formation holds about 13 tcf of gas reserves (Lin and Finley, 1985)[10]. The data from the East Texas basin were used to study the effect of fracture numbers. In addition, the Dakota field in the San Juan basin was used to study the fracture orientation (longitudinal versus transverse). Last but not least, the Uinta Basin was selected to study the effects of permeability on well performance. Fig. 3.1 shows all the tight gas basins in the USA. It is important to point out that all of these basins are unique and the results and conclusion are based on each basin and they are not valid for a general conclusion.

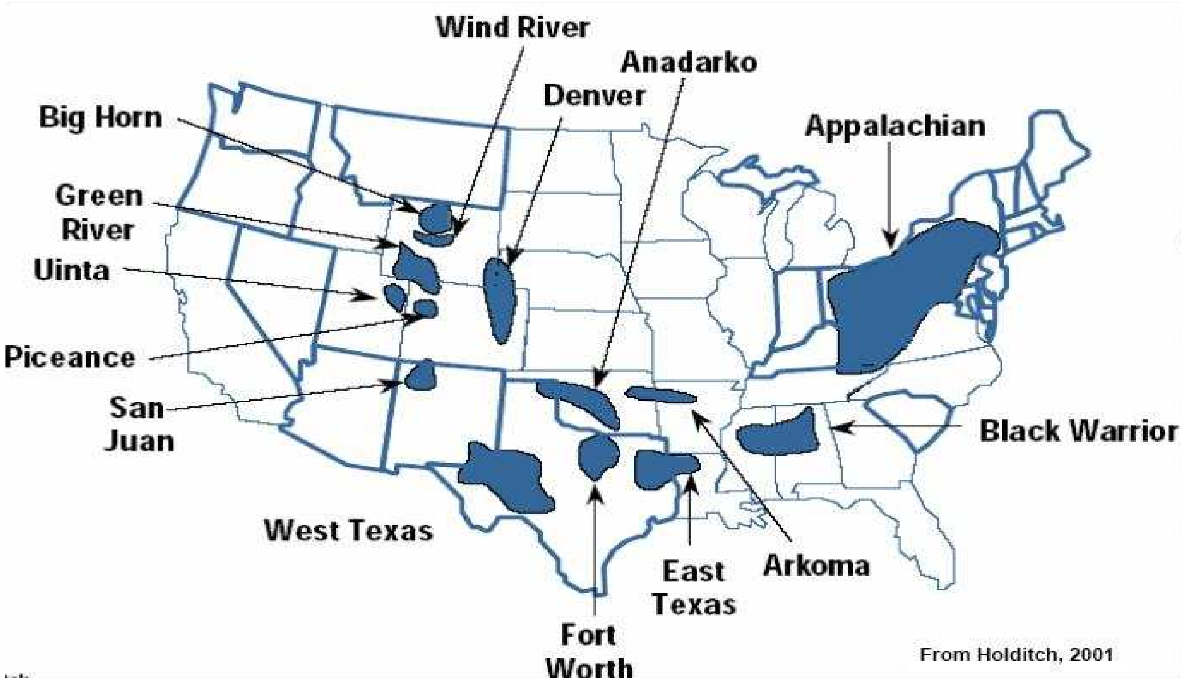


Fig. 3.1 Tight sandstone basins in the USA

For all the cases studied in this thesis, if a horizontal well is drilled without fractures in the system, then the horizontal well is treated as one source. In cases of one longitudinal fracture created along a horizontal well, the fracture is taken as the source, and the inflow to the wellbore is neglected. For multiple transverse fractures, each fracture is treated as a source and the fracture has infinite conductivity. For infinite conductivity fractures, each fracture is further divided into several smaller sources with uniform flux to count for the flow converging. Superposition principle is applied to pressure response to the flow field for the multiple source cases.

3.1 Non-Fractured Horizontal Well Length

One of the main parameters when drilling a horizontal well in tight gas formations is the well length. To study the effect of horizontal well length on well productivity, typical data from the Appalachian basin was used. The reservoir and fluid data are listed in Table 3.1. The reservoir drainage area was selected to be 320 acres so that plenty of different wellbore sizes could be tested. The well was placed in the middle of the reservoir. Fig. 3.2 is the set up for this experiment. This kind of well would resemble an open-hole completion, where no casing is placed.

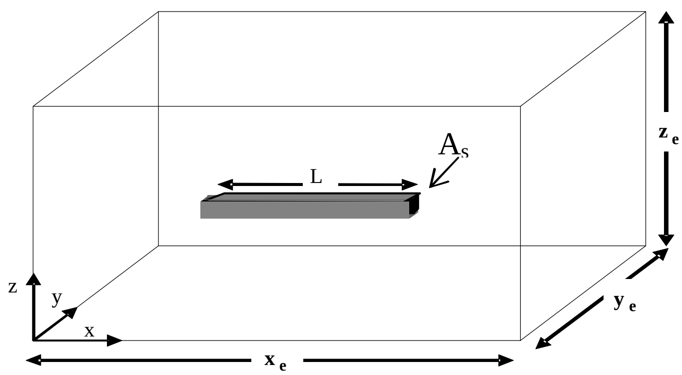


Fig. 3.2 Set up for length experiment

Table 3.1 Wellbore, reservoir and fluid data[11]		
Well Diameter	0.5	Ft
Drainage Area	320	Acres
Reservoir Thickness	200	Ft
Vertical Permeability	0.01	Md
Horizontal Permeability	0.1	Md
Reservoir Temperature	180	^oF
Reservoir Pressure	3000	Psi
Gas Gravity	0.69	
Wellbore Flowing Pressure	500	Psi
FVF	0.0371	
Formation Compressibility	3.00E-06	1/psi
Compressibility Factor	0.945	
Porosity	10%	

Fig. 3.3 shows the results of production rate as a function of time. It is clear from this plot that the longer the well the better its performance. However, it can be noticed that that as the wellbore reaches a certain length, the increase in production rate slows down. This can be clearly demonstrated when analyzing cumulative production and percentage of rate increase versus wellbore length, as shown in Figs. 3.4 and 3.5.

The advantage of a longer well length reaches a plateau when the wellbore length is close to the reservoir dimension. Since longer length will cost more in drilling and completion, there should be an optimal length which is not only directly related to the reservoir dimension but also affected by the reservoir properties, such as permeability. For the example case, a squared-shape reservoir geometry is assumed at 320 acres, with the length and width of the reservoir of 3733-ft. As shown in Figs 3.4 and 3.5, the most attractive wellbore length would be at around 2500 ft. Fig 3.5 shows that after 2500-ft length, the production increase (rate at any length compared with the rate at 500 ft wellbore length) approaches a constant. Beyond this point, increasing wellbore length will no increase the production rate enough to justify the addiction costs of creating a longer wellbore. For different reservoir conditions, the optimal length varies, and the optimal length should be identified for individual cases.

Realizing that even the flow rate of horizontal wells in low permeability formations may not be high enough to cause a significant pressure drop in the wellbore, it does not limit the case that frictional pressure will affect the well performance. When wellbore length increases it will increase the frictional pressure in the wellbore in two counts: longer wellbore and higher flow rate. At certain conditions wellbore pressure drop in longer horizontal wells can also limit the well performance. The pressure drop in the wellbore in such situation should be considered when designing the wellbore length.

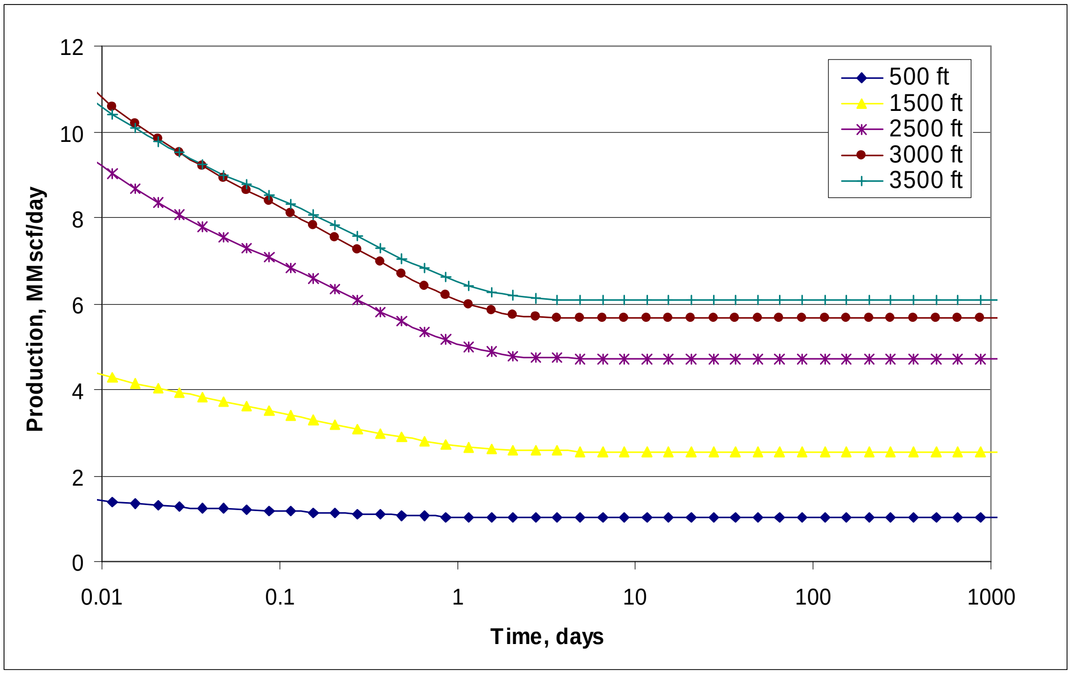


Fig 3.3 Effects of wellbore length on daily production

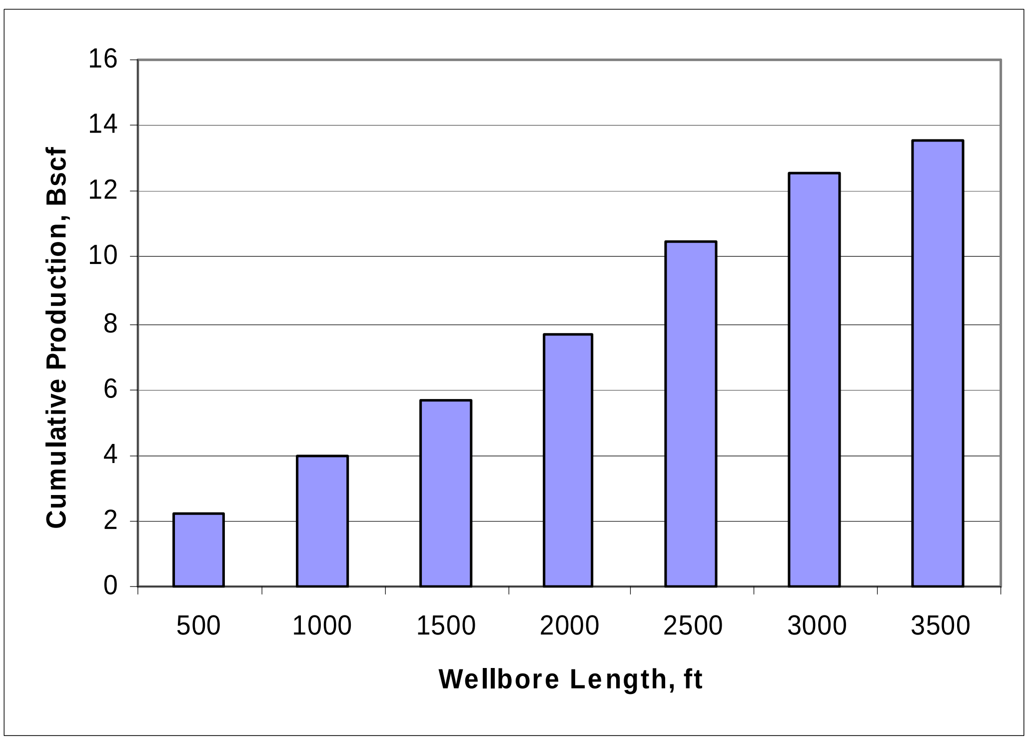


Fig. 3.4 Effects of wellbore length on cumulative production

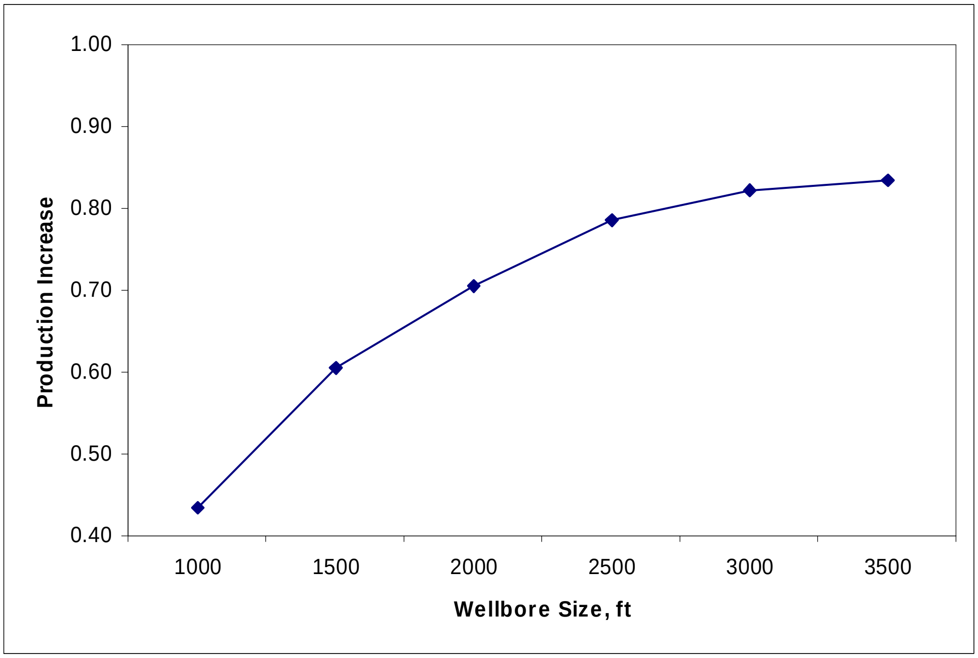
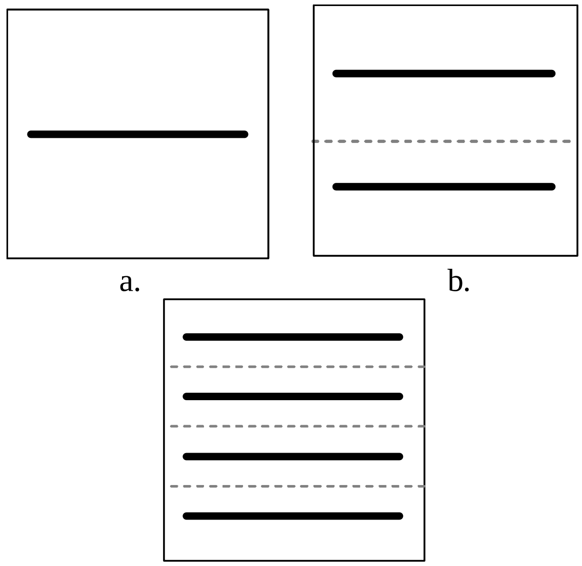


Fig. 3.5 Percentage increase in cumulative production due to wellbore length increase

Later in this chapter, fractured horizontal wells will be studied. The wellbore length in this case should be dictated by the number of fractures and the position of those fractures in the reservoir to best produce the well.

3.2 Well Placement and Spacing

Well placement and spacing are other important issues that affect performance of horizontal wells in tight gas formations. This study was conducted using the same basin data as shown on Table 3.1 using a 320 acre squared reservoir. Three different well placement plans were considered; one 3000-ft well (Fig. 3.6a); dividing the reservoir equally into two regions, and each sub-are has a 3000-ft well (Fig. 3.6b); and further dividing the reservoir into four sections with four 3000-ft wells located at the middle of each sub-section (Fig. 3.6c) thus, the drainage area for each case is 320 acres in plan a, 160 acres in plan b and 80 acres in plan c.



a. b.

c.

Fig. 3.6 Plans for drainage area study

The predicted production history for the well spacing/placement study is plotted in Fig. 3.7. Obviously, more wellbore means more reservoir contact, and directly results in higher production rate (plan c versus plan a). But the increase in flow rate is not linearly proportional to the total contact with multiple wells. When more wells are placed, the drainage area for each well becomes smaller (subdivided area by the dashed lines in Fig. 3.6), and the transient flow period is shorter. Once the boundary is reached, the wells will drain from the same drainage area, and the advantage of multiple wells will fade. For lower permeability reservoirs, the benefit of increasing number of wells is more pronounced than for higher permeability formations. The optimal well spacing and placement for each field condition is suggested to be obtained combining the production gain and the cost of placing the wells.

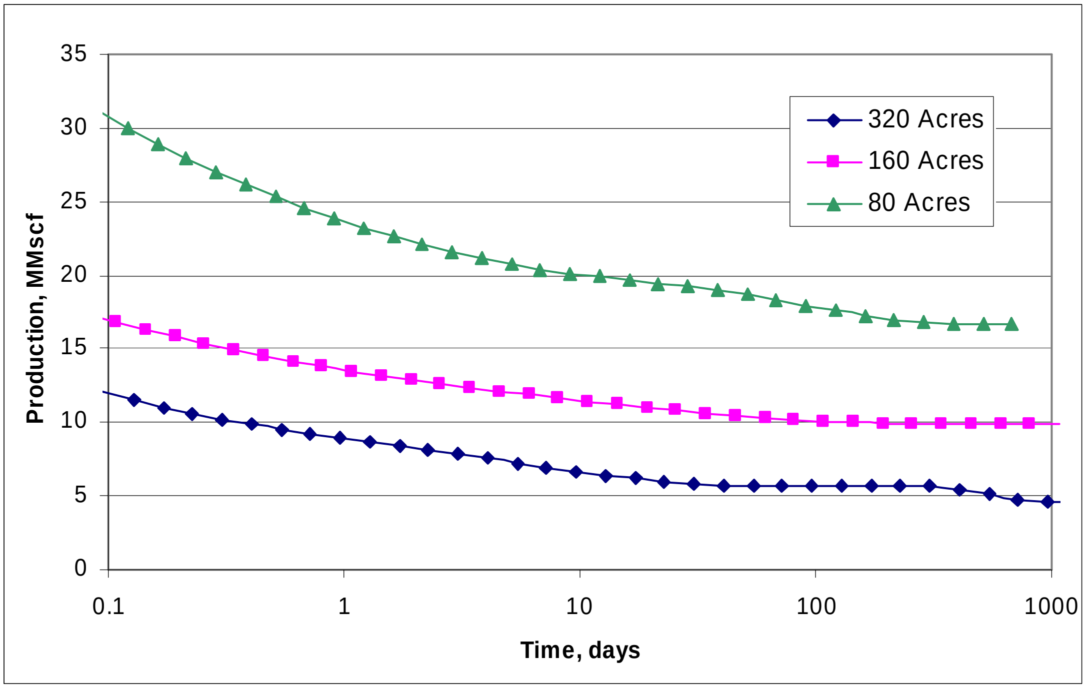


Fig. 3.7 Production from different drainage areas

The next section will show that sometimes, horizontal wells themselves are not enough. Hydraulic fracture may prove to be more efficient and a more economic option.

3.3 Fracture Geometry and Placement

Frequently, horizontal wells in tight gas formations are fractured to enhance the wellbore contact with the reservoir. The well can be drilled so that the created fractures can be longitudinal or transverse. In an ideal case, if the fracture is fully penetrated so that vertical permeability does not affect the performance, and if the fracture is infinitely conductive, the orientation of the fracture will not change the performance under the assumption of k_H is the same in all directions. In other words, longitudinal fracture and transverse fracture will have the same production performance. Obviously, it is easier to create more fracture volume in the case of transverse fractures because we can place more than one fracture along the wellbore, and thereafter, transverse orientated fractures would result in higher well performance comparing with a single longitudinal fracture case. In addition, ideally, fractures are created perpendicular to the dominating permeability direction. Then on one to one case, there is no difference between longitudinal and transverse fractures. Realistically though, the formation stress distribution controls the direction of the orientation of fractures, and more likely the ideal case is not easy to establish.

If fractures are not fully penetrated, vertical permeability does affect the productivity of the well. Again, for a fixed total fracture volume, two fracture geometries are studied (Fig. 3.8). This experiment was conducted using synthetic data as shown in Section 3.1.

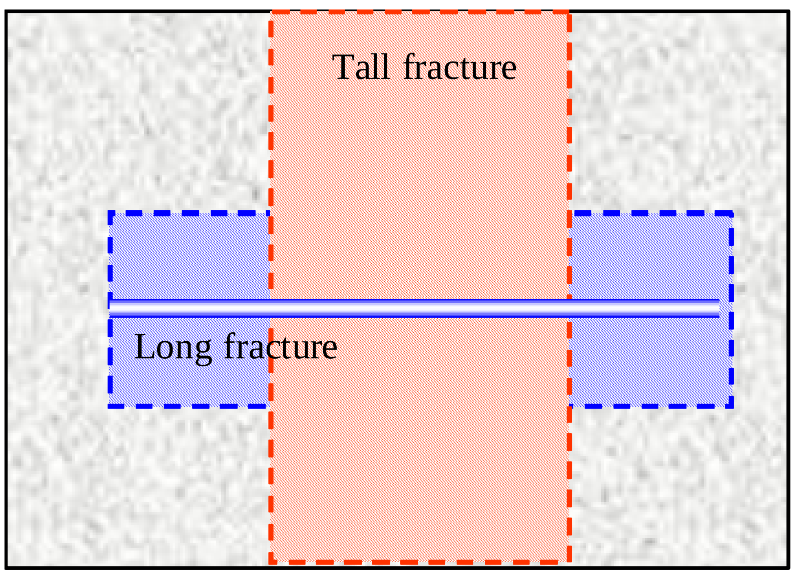


Fig. 3.8 Schematic of partial or fully penetrated fracture

The tall fracture fully penetrates the formation thickness with shorter fracture length, while the long fracture covers the wellbore length but partially penetrated in the vertical direction. The longer fracture has higher productivity than the taller fracture (Fig. 3.9) with a reasonable vertical permeability, especially in the transient period. Thus, if the total volume of a fracture is fixed, we can scarify some fracture height for increased fracture length to get higher productivity. This advantage of longer fracture will diminish as vertical permeability decreases.

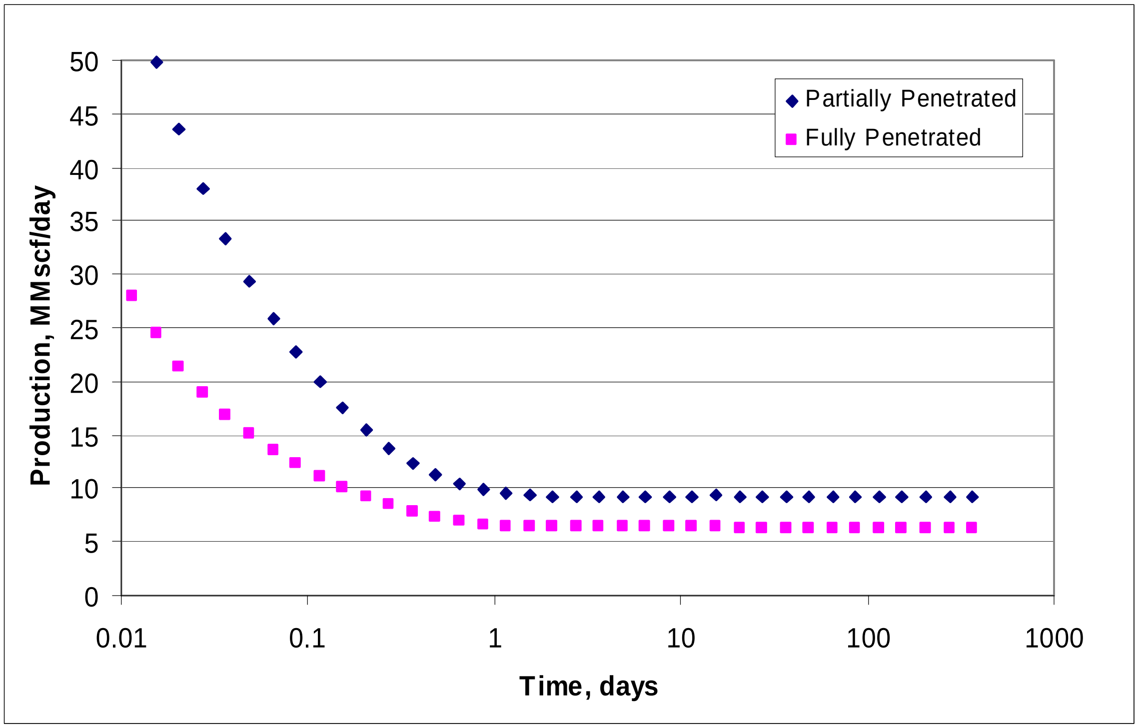


Fig. 3.9 The effect of partial penetration of fracture

3.4 Ideal Number of Transverse Fractures

In low permeability formations, the most sensitive parameter among the reservoir properties to well performance is the permeability. In general, hydraulic fracturing can be used to create flow path in tight sands, and more than one transverse fracture are more efficient to stimulate well performance. This study shows that if multiple fractures are applied, the effect of permeability condition should be considered to determine the optimal number of fractures that can maximize the benefit of stimulation. Typical East Texas field data from Percy-Wheeler field, Whelan field and Appleby field were used in this study. The input data used in the study are shown in Table 3.2. Notice the permeability differences in the three fields with the permeability of Appleby North field being almost one order of magnitude smaller than the one for Whelan field (0.01 versus 0.09). The study is conducted based on an assumed and fixed drainage area (80 acres) for all three cases, and an anisotropy ratio, k_H/k_V, of 10 is used for all three cases.

Table 3.2 Input data for the East Texas basin[10]

Property	Whelan	Percy W.	Appleby N.
Net Pay, ft	200	200	60
Hor. Perm, md	0.092	0.052	0.01
Porosity, %	8.8	10.3	8.8
Res. Pressure, psi	3500	3000	2800
Res. Temp., oF	220	245	254
Gas Gravity	0.63	0.62	0.61
Compressibility, 1/psi	1.25E-05	1.25E-05	1.25E-05
Assumed Data			
Area, acres	80	80	80
Comp. Index	0.85	0.85	0.85
Well Press., psi	500	500	500
Viscosity, cp	0.0244	0.0244	0.0244

The DVS method was used to calculate the productivity of three different formation conditions, and at different fracture numbers. Up to five fractures were used in each case. The results of fractured well performance are presented as the production history of a horizontal well with 1 to 5 fractures placed along the well for each field. In each case, a fracture length ($2x_f$) of 1000ft is used for each fracture (for example, when five fractures are created, the total fracture length will be 5000 ft). The fractures were fully penetrating in height and were half an inch in width. Fig. 3.10 is the production rate result for the Whelan field condition (horizontal permeability is 0.09 md), Fig. 3.11 is for Percy Wheeler field (0.05 md) and Fig. 3.12 is for Appleby North field (0.01 md).

Clearly, the higher-permeability field has better well performance. Also, with more fractures created along a well, the production rate is higher than fewer fractures for all three fields. The interesting fact is that when enough fractures are placed along the wellbore, increasing fracture number does not affect the production rate as significantly as at low fracture numbers. For example, the production increment when placing two fracture rather than one fracture is much higher (25 Bscf) than when add the third fracture to the second fracture (15 Bscf), and the increment of production rate becomes smaller as the fracture number becomes higher.

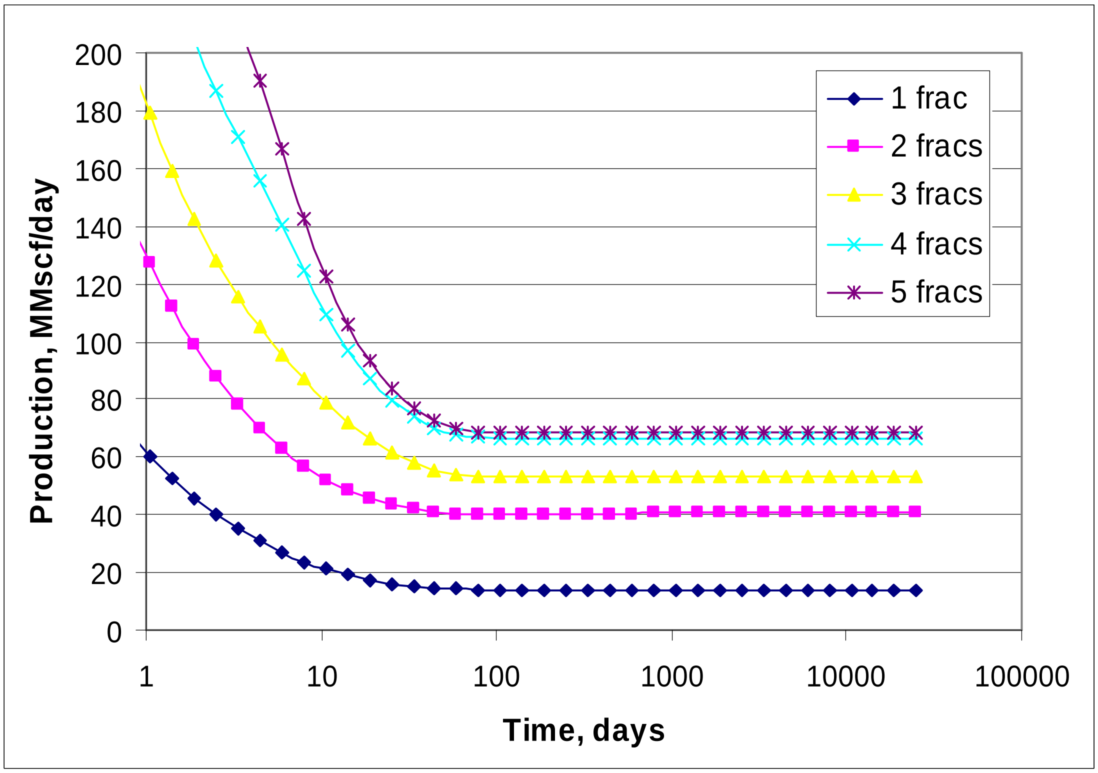


Fig. 3.10 Production history for the Whelan field condition

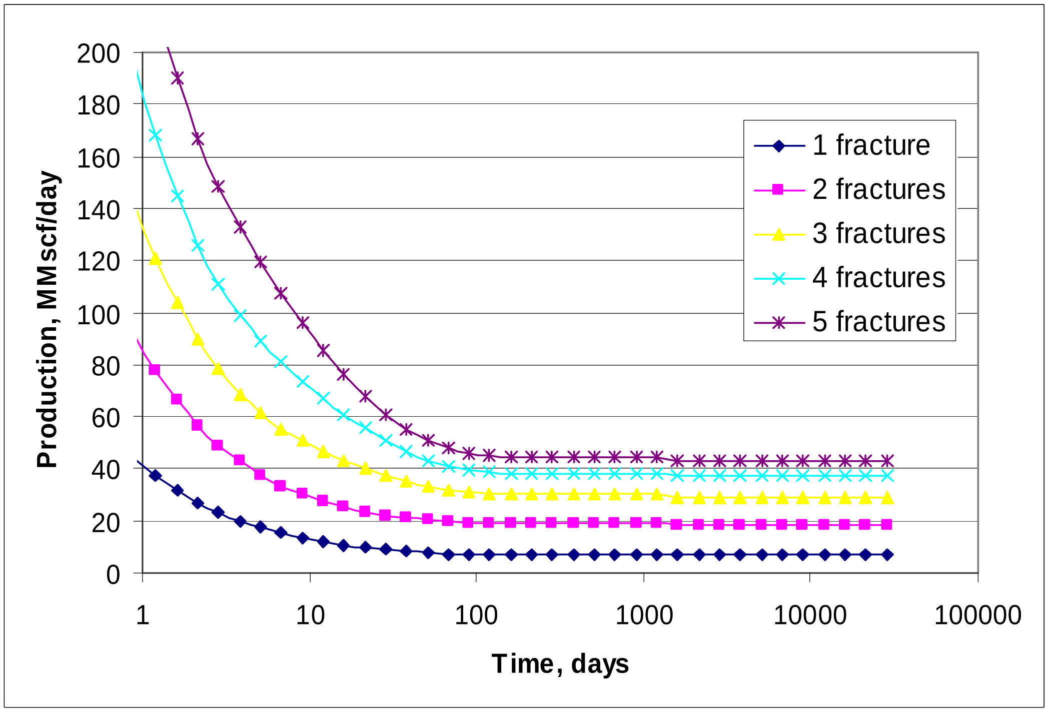


Fig. 3.11 Production history for the Percy Wheeler field condition

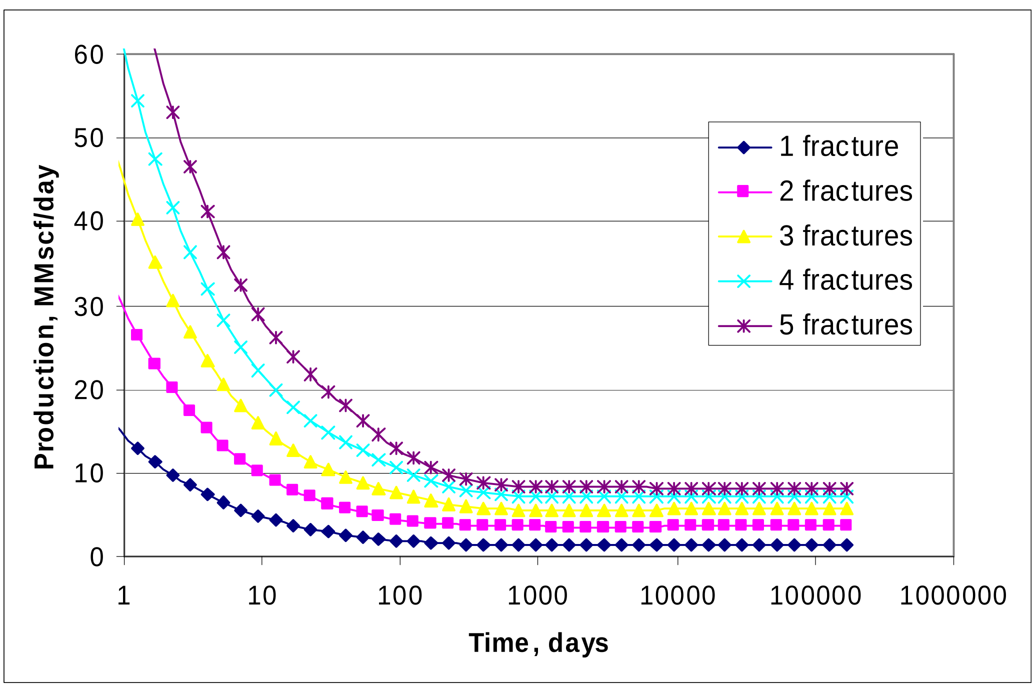


Fig. 3.12 Production history for the Appleby North field

This feature is more obvious in higher permeability formation compared with lower permeability formations. In the Whelan field case, the performance for 5-fracture case is almost the same as the one for four fractures after 10 days, implying that adding more fractures does not bring the advantage as expected. If we plot the cumulative production versus fracture number for 1000 days producing time (Figs. 3.13-3.15), we can see that the cumulative curve becomes flat after four fractures in the Whelan field case (Fig. 3.13), meaning the optimal fracture number at this condition should be 4. Meanwhile, the cumulative production curves still have strong positive slope at 5 fractures for the Percy Wheeler field case (Fig. 3.14) and the Appleby North field (Fig. 3.15), indicating that production can be further improved with more fractures placed along the wellbore. The difference of the well performance responding to the number of fractures in different field condition is mainly caused by the permeability difference. At higher permeability, the transient flow period is shorter. Once the drainage boundary is reached (pseudo steady state or steady state flow conditions), multiple fractures will start draining from the same drainage area, and the benefit of more fractures will diminish. This study shows that for each field case, there should be an optimal fracture number for transverse fractures along a horizontal well. For higher permeability field, the optimal fracture number is smaller than for lower permeability reservoirs. The optimal fracture number is not general, and should be studied for each individual field condition.

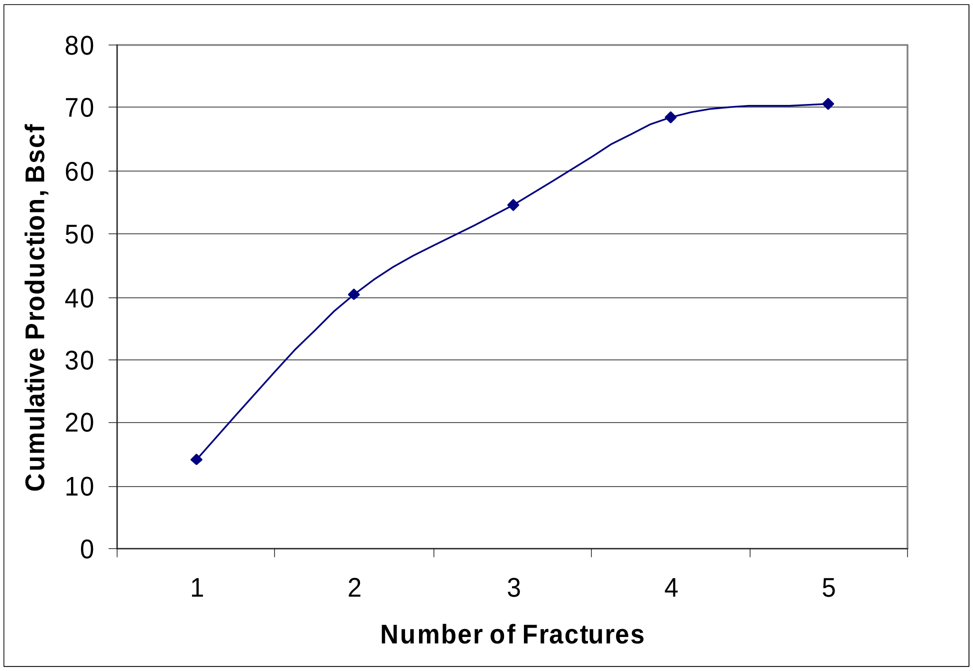


Fig. 3.13 Cumulative production for the Whelan field

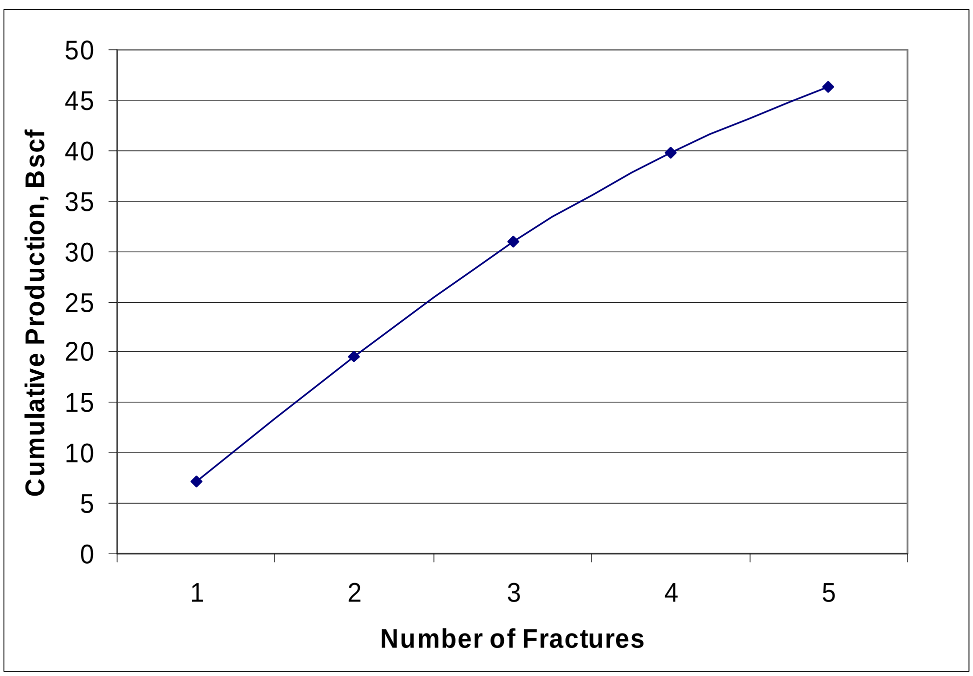


Fig. 3.14 Cumulative production for the Percy Wheeler field

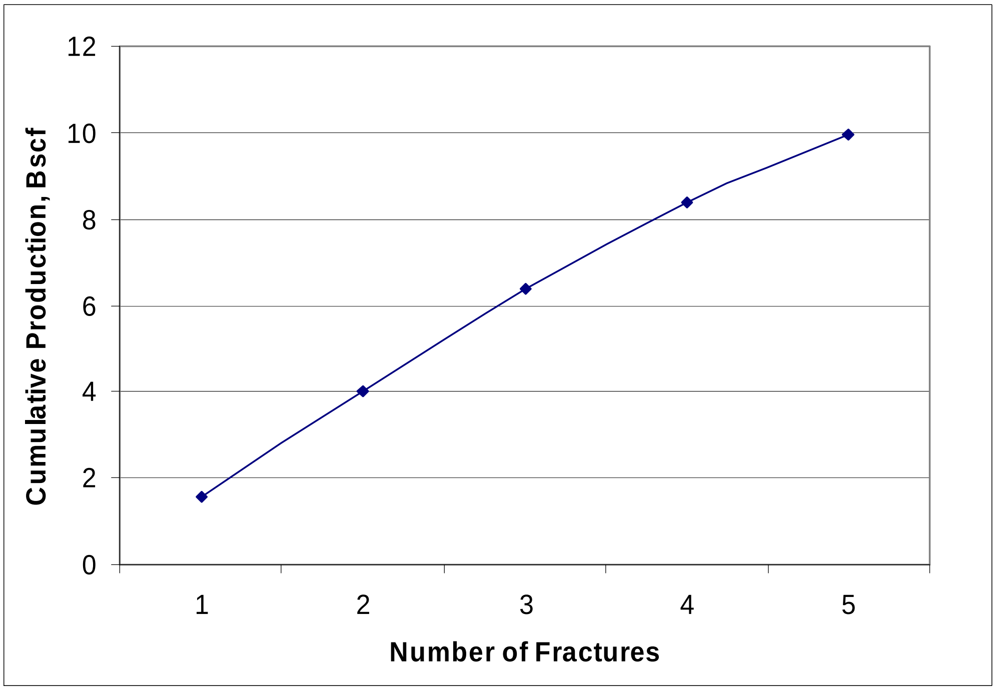


Fig. 3.15 Cumulative production for the Appleby North field

The following section shows the performance results for when the total fracture volume is kept at a constant value.

3.5 Constant Volume Transverse Fractures

In this next study, typical data from the East Texas basin were used. Table 3.2 shows reservoir, wellbore and fluid data for all the three reservoirs that were used, and the source of the information. When comparing multiple transverse fractures it is obvious that the more fractures you have the better the performance. If there is no limit to the volume of proppant pumped into the ground, and the fractures can be all with the same dimension, then the more fractures you pump the more gas is going to be produced. Fig 3.16 shows the comparison between cumulative production of the case where all the fractures are of equal value and the case where the volume of the fractures is fixed.

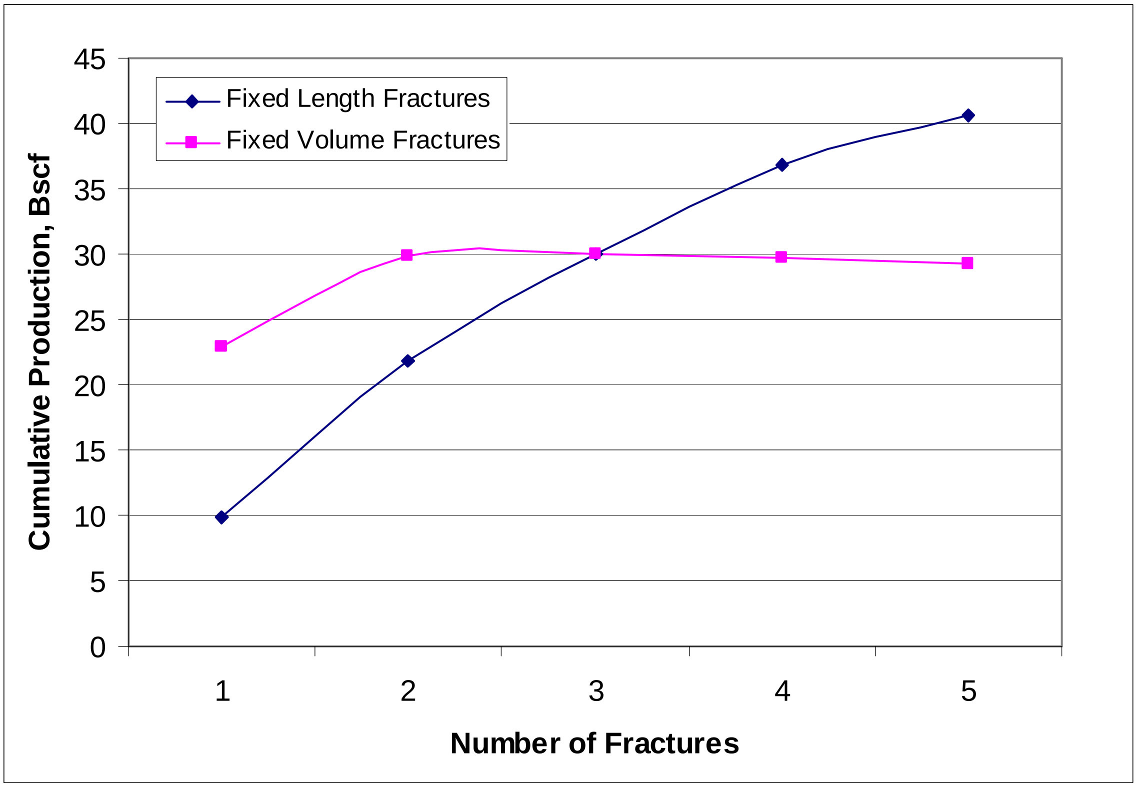


Fig 3.16 Comparison between equally long fractures and fixed volume fractures

For both cases, the fractures were fully penetrating on the z-direction and with half-inch width. For the fixed fractured volume case, the fractures kept a total volume of 12500-ft^3. In other words, if there were three fractures, they would be 500-ft half-length fracture. This is why in this case they both present the same cumulative production. For the equally long fracture cases, the fractures were fixed at 250 ft half length.

As mentioned in section 3.4, even when considering equal volume fractures, it is obvious that the production increase is slowing down as more fractures are added. This is due to one fracture draining the area of the offset fracture. To overcome the economic constraint, the volume of all fractures was fixed. That way the economics for each case would be somewhat similar. The total volume of all fractures was fixed. The width of the fracture was divided as the number of fractures increased.

In the Percy-Wheeler and the Whelan field the wells showed a significant increase in production once the second fractured was placed. After that, the production stabilized and gradually decreased after the fourth fracture was placed. The reason for that is because the smaller fractures do not take as much advantage of the horizontal permeability as the longer but fewer fractures do. On the other hand, the production did not decrease sharply because the more fractures there are, the more drainage area they are going to cover. The results for this experiment can be seen in Fig 3.17, and Fig. 3.18.

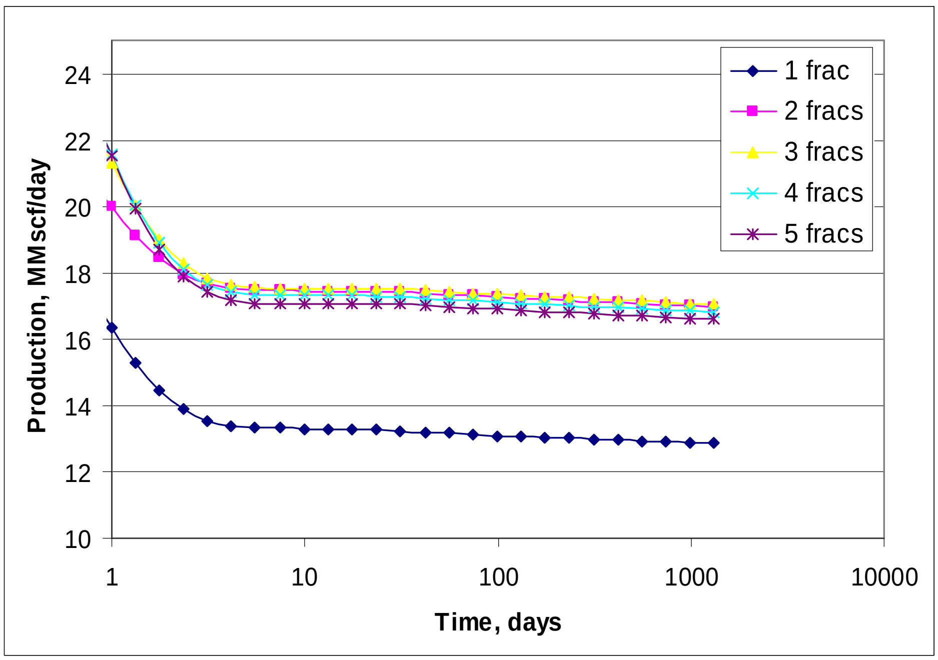


Fig 3.17 Daily production in the Whelan field

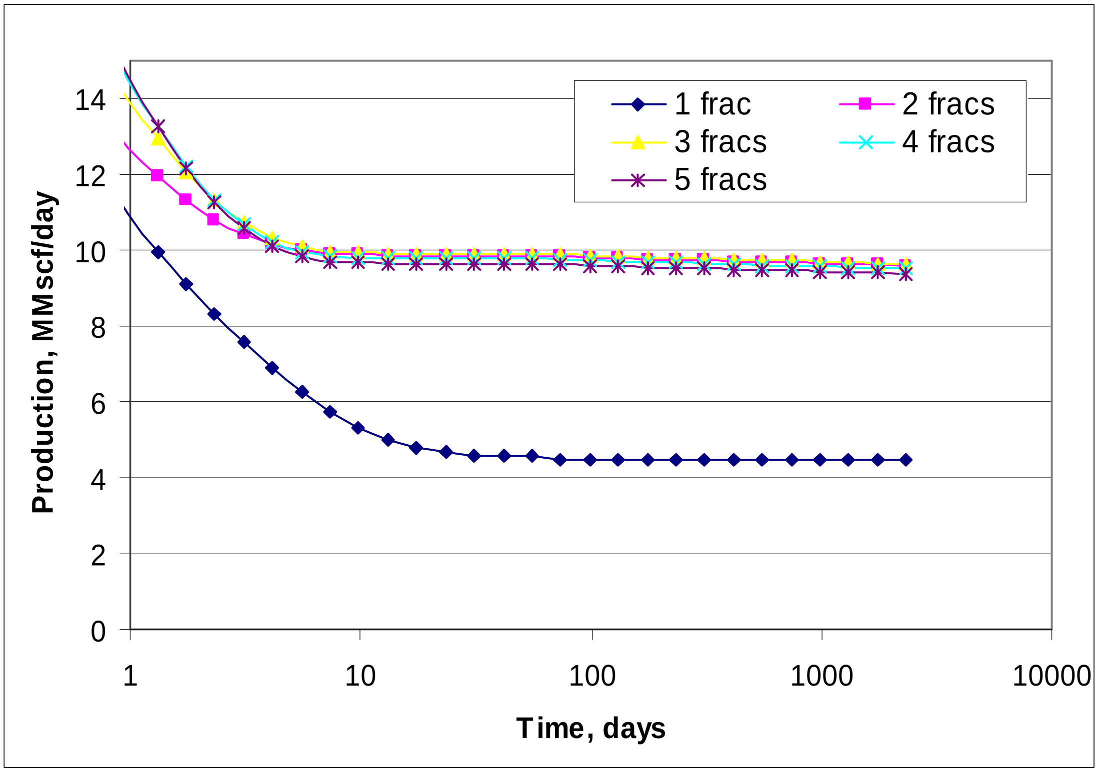


Fig 3.18 Daily production in the Percy-Wheeler field

In the Appleby North Field, all cases gave similar results in production. The reason for that is that the permeability of that field is so small that the increase in production due to more fractures is practically insignificant. This field would have to be developed with massive hydraulic fractures in order to obtain economical results. The results for this experiment are shown in Fig. 3.19.

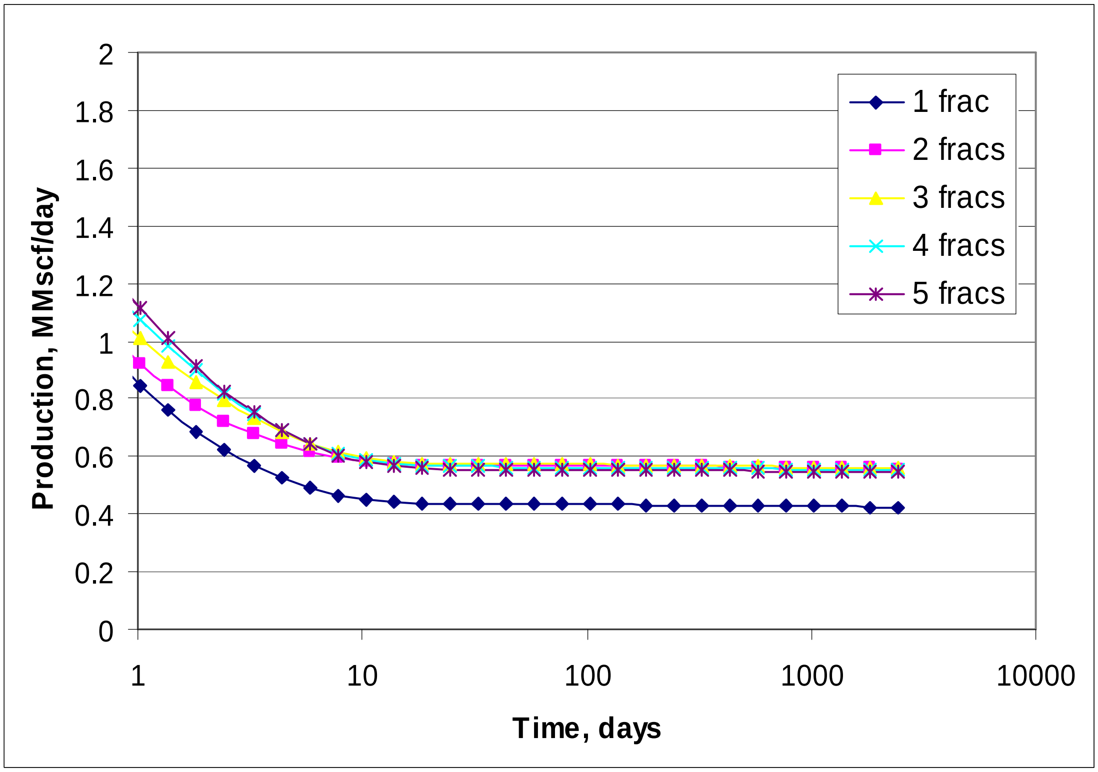


Fig. 3.19 Daily production in the Appleby North field

The results from this experiment show that in these fields specifically, if we want to the wells to perform at their best potential keeping a fixed volume for all the fractures, the best results are in between 2 and 3 fractures. This does not mean that all reservoirs should be hydraulically fractured only twice for all reservoir. This is a case specific study; in other words, each case has to be studied separately. In all the experiments performed the fractures were kept symmetrically divided within the reservoir. In order for this to happen in the case of 5 fractures we would have to penetrate at least 80% of the reservoir.

3.6 Longitudinal versus Transverse Fractures

Hydraulic fractures in horizontal wells can be either longitudinal or transverse. Prior to drilling the well, a study of the stress field of the formation has to be done in order to determine the direction in which the horizontal well is going to be drilled. This study is important because the orientation of the well determines the type of fracture that is going to be created. In some cases a longitudinal fracture might be more economical and in others, transverse fractures might be more attractive. An apparent advantage of longitudinal fractures is that the stimulation process is simpler. Most likely, less number of fractures needs to be created, and therefore, the cost would be lower. The longitudinal fracture can be efficient, especially when the reservoir is fairly homogeneous. For heterogeneous formations, longitudinal fractures may have limited access to formation fluids.

The study of fracture orientation was conducted using the data from the Dakota field in the San Juan basin. Table 3.3 shows the reservoir, wellbore and fluid data. To compare the effect of one longitudinal fracture with multiple transverse fractures, we generated the cumulative production for one longitudinal fracture, and one to five transverse fractures. Fig. 3.20 shows the result of all the cases. In this study, the total fracture volume for each case is fixed to obtain a fair comparison of longitudinal fractures to transverse fractures. In another words, the individual fracture volume for multiple fractures is smaller than the single fracture case. It is also assumed isotropic permeability field in the horizontal plane ($k_x = k_y$).

Table 3.3 Dakota field data[12]		
Wellbore Length	3000	Ft
Well Radius	0.3	Ft
Drainage Area	320	acres
Net Pay Thickness	100	ft
Fluid Viscosity	0.0162	cp
Reservoir Temperature	175	^oF
Reservoir Pressure	3500	psi
Horizontal Permeability	0.1	md
Vertical Permeability	0.01	md
Compressibility Factor	0.945	
Gas Gravity	0.74	
Wellbore Flowing Pressure	550	psi
Formation Porosity	8.50%	
Total Compressibility	0.000004	psi^{-1}
Formation Volume Factor	0.0144	scf/bbl

From Fig. 3.20 it can be seen that if we only create one fracture, longitudinal fracture has a slightly better productivity than transverse fracture. This is because of a better communication between the fracture and the wellbore. Fig. 3.20 also shows that for a total fixed fracture volume, two transverse fractures yield the highest production rate for the given condition. After that, more fractures placed result in smaller fracture geometry, therefore the effect of extended contact between the fractures and the wellbore starts reducing. Since the production rate differences for different fracture design are not very significant, the economic fact should be considered when determining the fracture orientation and number of fractures.

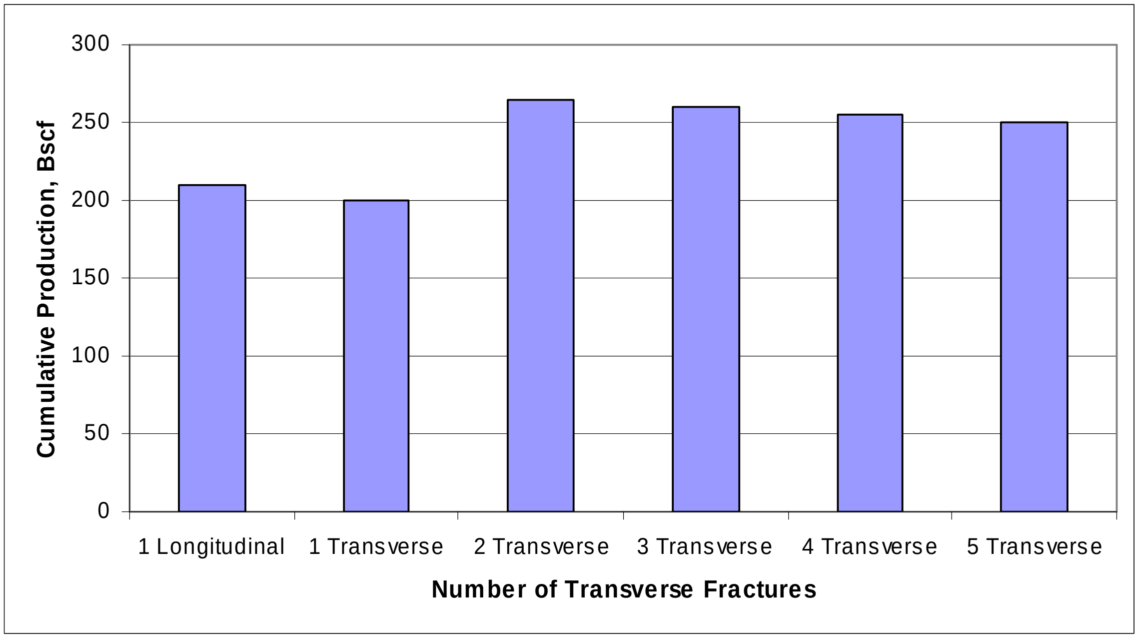


Fig. 3.20 Well performance of different number of fractures

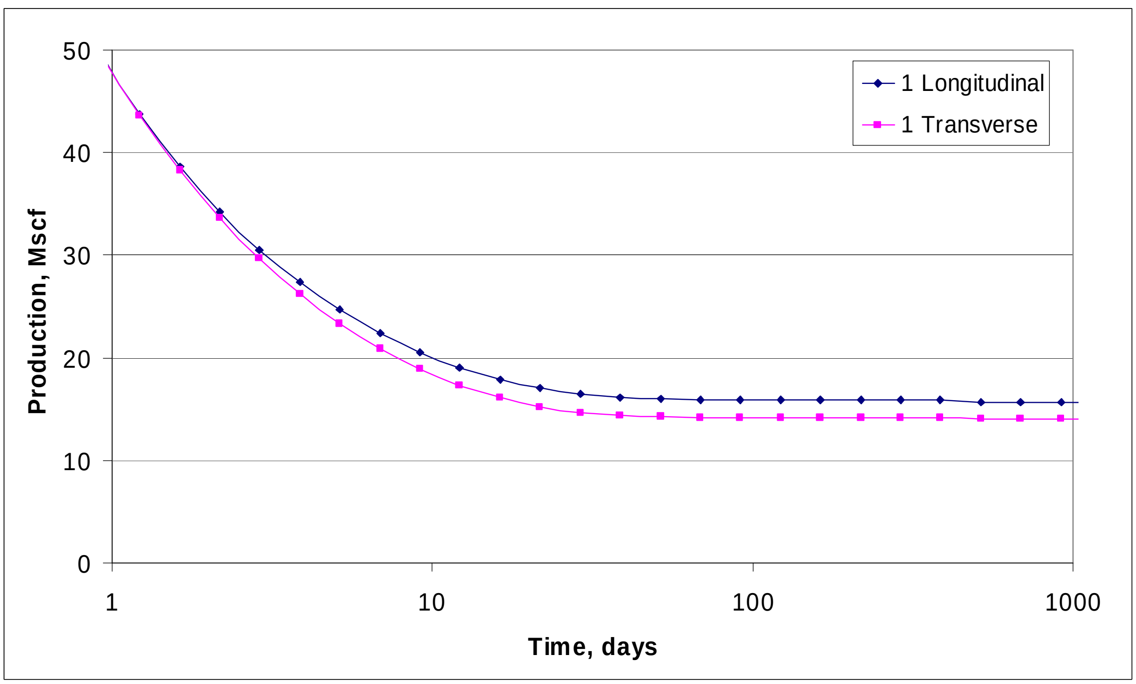


Fig. 3.21 Daily production of longitudinal and transverse fractures

Fig. 3.21 shows the daily production from just two cases: one longitudinal and one transverse fracture. It is important to point out in this case that even though the difference is fairly small, both, transient and pseudo steady state times, the well produces more when it has a longitudinal fracture. The longitudinal fracture takes more advantage of vertical permeability, k_v. Even though the k_v is smaller by a factor of 10 compared to the horizontal permeability, k_h, it is still significant enough to give the longitudinal fracture the edge over the transverse fracture.

In the case of transverse fracture placed in the middle of the reservoir, a gas molecule that is placed in the edge of the reservoir takes a very long time to get to the fracture, and it is fair to assume that it travels on the horizontal all the time. In the transverse fracture case that molecule can travel vertically to the fracture, therefore making it faster for it to reach the wellbore.

Notice the difference in conclusions about the optimal fracture number. If the volume of the fractures is not limited, and each fracture created can have a similar geometry, the optimal fracture number is higher than the case that the total fracture volume is fixed.

3.7 Reservoir Vertical Permeability Study

As mentioned previously, reservoir permeability is the most critical parameter that dictates the success of a well in tight gas formations. This includes horizontal permeability and vertical permeability. Tight gas formations are considered to be tight if the horizontal permeability is below 0.1 md. The effect of permeability sometimes is presented through anisotropic ratio (the ratio between the reservoir's horizontal and vertical permeabilities). In this study typical well data from the Uinta Basin was used. The reservoir, well and fluid data is presented at Table 3.4. The first case studied was done by using an anisotropy ratio of 10, which is the authentic data from the field. The second and third cases were done by changing the vertical permeability so that we would get an anisotropy ratio of 100 and 1 respectively. For all three cases, a horizontal well, a transverse and a longitudinal fracture were tested. The two fractured cases (transverse and longitudinal) gave equal results because the volume of the fracture was exactly the same and the only change was the orientation of the fracture. Since the horizontal permeability is assumed to be equal in the x and y directions, there are no changes in the production performance of both of these cases. These two fracture types are fully penetrated on the z-direction, and since there are no modifications in the horizontal permeability in all cases, it is noted on Fig. 3.22 that the performance of these three different anisotropic ratios remains the same.

Table 3.4 Uinta basin data[13]		
Wellbore Length	1500	Ft
Well Diameter	0.33	Ft
Drainage Area	80	Acres
Net Pay Thickness	100	Ft
Fluid Viscosity	0.155	Cp
Reservoir Temperature	150	^{o}F
Reservoir Pressure	2500	Psi
Horizontal Permeability	0.1	Md
Compressibility Factor	0.86	
Gas Gravity	0.71	
Wellbore Flowing Pressure	900	Psi
Formation Porosity	14.00%	
Total Compressibility	0.0000125	psi^{-1}
Formation Volume Factor	0.0371	scf/bbl

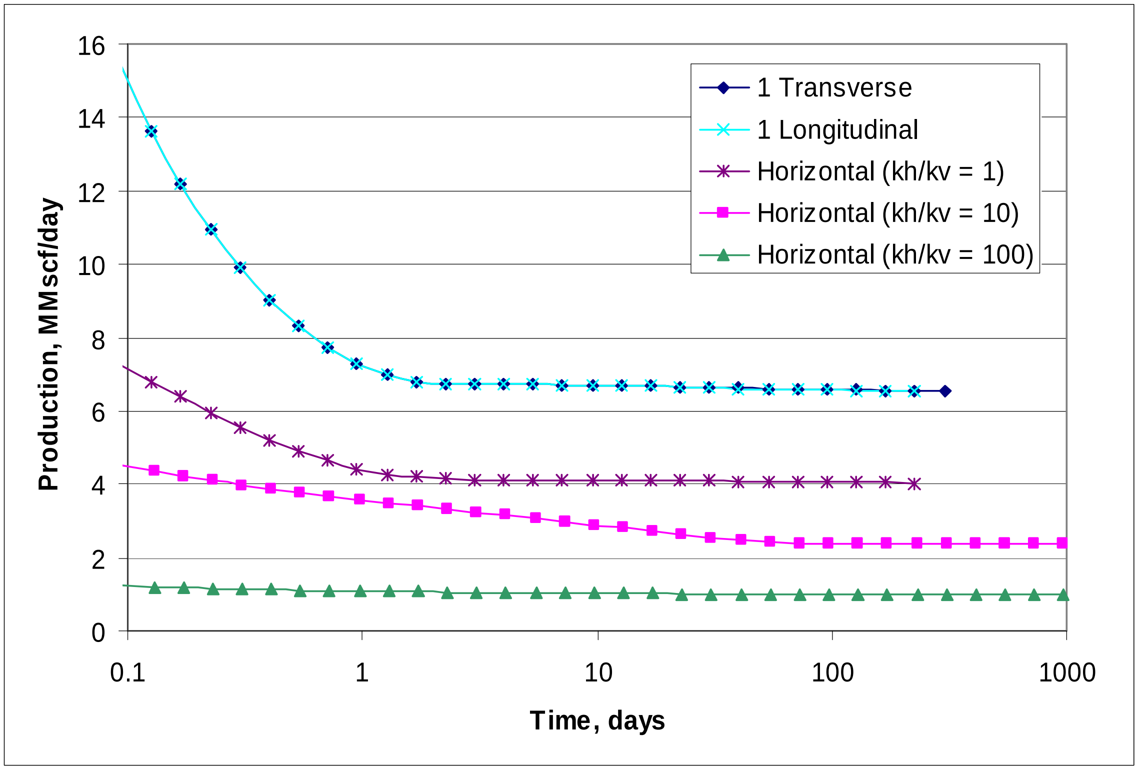


Fig 3.22 Production performance of different anisotropy ratios in the Uinta basin

There are several conclusions that can be taken from Fig. 3.22. The non-fractured horizontal wells, give the worst production. This happens in all cases because the wellbore has less contact with the reservoir than in the fractured cases. However it is noticed that in the case where the reservoir has a satisfactory vertical permeability in the case of the anisotropy ratio being 1, the production approaches to that of the fractured cases. This might be an indicator that fracturing stimulation is not necessary for this field and the horizontal well itself might be satisfactory. Also the transient period ends at about the same time as the fractured case, indicating that the pressure hit the boundaries of the reservoir at about the same time. On the case of the anisotropy ratio of 10 the pseudo steady state period starts at a later time, and the case of the anisotropy ratio of 100 it takes even longer to reach that period. Also, the daily production from these two cases are significantly lower than that of the fractured reservoir. This is a clear indication that the reservoir needs to be fractured to better perform.

CHAPTER IV
CONCLUSIONS AND RECOMMENDATIONS

The DVS method used to study the performance of horizontal wells, with or without fractures, in low-permeability allowed for a smooth transition between transient and pseudo steady state periods. This study was conducted for length of horizontal wells, well spacing, ideal number of transverse fractures, longitudinal versus transverse fractures, and reservoir permeability. A blend of real reservoir data and assumed data was used to draw the following conclusions:

1. For non-fractured horizontal wells, the longer the wellbore is the better the performance. After a certain length the increase in production is diminished.
2. In low permeability gas reservoirs, the smaller the drainage area for a horizontal well the better the production results will be.
3. In the East Texas reservoirs studied, if maintaining a constant fracture volume for all the fractures, 2 or 3 transverse fractures are ideal. If this number of fractured is raised the production starts decreasing.
4. Transverse fractures proved to be ideal over longitudinal fractures in the case studied because it takes better advantage of both horizontal permeability and drainage area.
5. Horizontal Permeability is the main factor in determining which type of fracture will give the most productivity. 2 or 3 fractures are ideal in the cases studied.
6. If the horizontal permeability is constant in all directions, there is no difference in production from a single transverse fracture or a longitudinal fracture, if they are placed in the center of the reservoir and if all production is coming from the fractures.
7. A non-fractured horizontal well may be satisfactory if the vertical permeability is sufficient.

This study was the first one to use the DVS method. Although this study was a good start on helping the industry on evaluating the performance of horizontal wells in tight gas formations, there is a large room for improvement and further study. The method offers features that were not used in this thesis. These features can be used with further research. Several conditions and constraints that are found in the field can be added to this study. These include the addition of the following:

1. Throughout the study the saturation was always assumed to be 100% gas, which is not always the case. Gas, water and oil are usually mixed in the reservoir and are brought to the surface. The method can be used to consider production of all these fluids.
2. With the production of these fluids, the frictional pressure drop inside the well is more clearly noticed, therefore it cannot be ignored.
3. Tilted wells and fractures can be taken into account by subdividing the well and the fractures into smaller blocks to resemble such cases.
4. Turbulent effect of gas flow was ignored since this is only present in higher permeabilities.
5. Lastly, economics have to be considered in order to determine if the well performance will be satisfactory.

NOMENCLATURE

DVS	Distributed Volume Sources
J_D	Dimensionless Productivity
q_D	Dimensionless Flow Rate
P_D	Dimensionless Pressure
k_H	Horizontal Permeability
kv	Vertical Permeability
kx	Permeability on the x-direction
ky	Permeability on the y-direction
kz	Permeability on the z-direction

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APPENDIX A
MATHMATICA PROGRAM

The Mathmatica® program is really simple to use. The running time may take between 10-15 minutes to run, when running the program for 5 fractures. First of all, the user has to define the reservoir dimensions and its permeability on the x, y and z-directions. After that on the line right below it, the user has to define the dimensions of the fractures. This is shown by arrow number 1 in Fig. A.1. The reservoir permeability is measured in md. The dimensions for the reservoir and the fracture are all in feet, however, the fracture dimensions are all specified to half-length. So for the example in Fig. A.1, we are defining the fracture to be 0.5-inch wide, 1000-ft long, and 200-ft high.

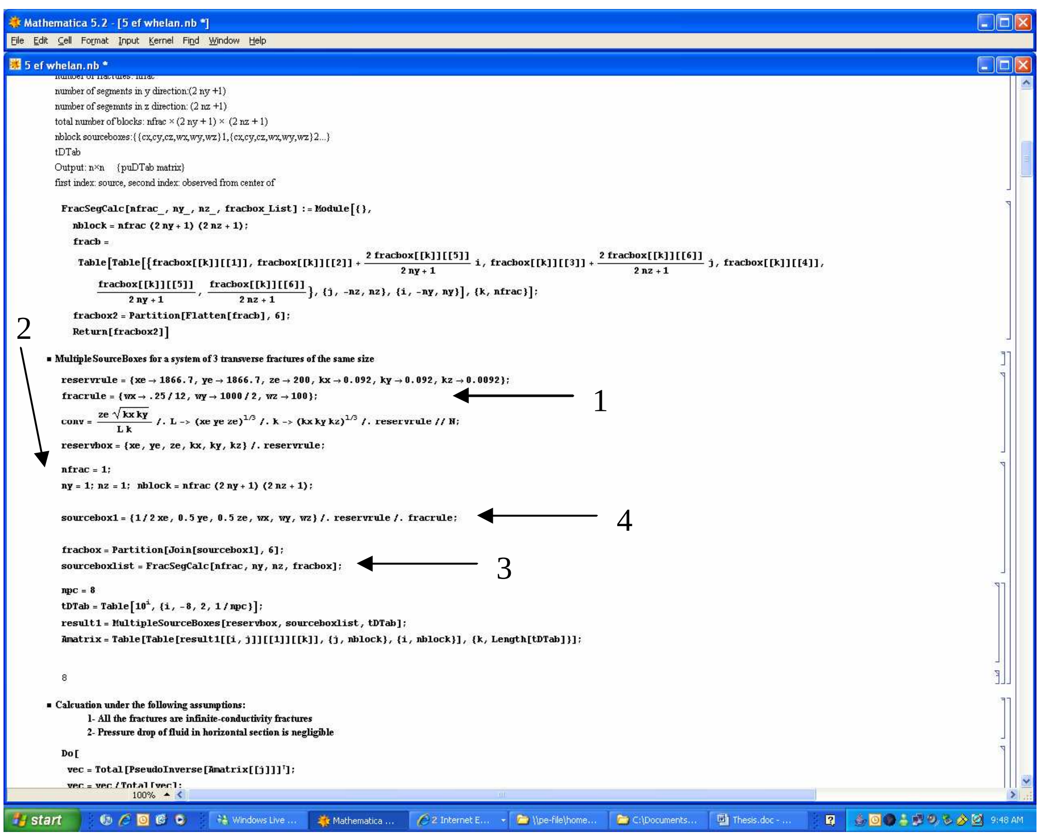


Fig. A.1 Display for 1 fracture setup

The next step is to specify the program how many fractures are going to be placed in the reservoir. This is indicated on arrows, 2 and 3. In this example the user is running for 1 fracture only. The location of the fracture is indicated by arrow 4. In this example the fracture is placed in the middle of the reservoir. Fig. A.2, shows an example modified to run for 5 fractures. Notice the 4 lines that are modified.

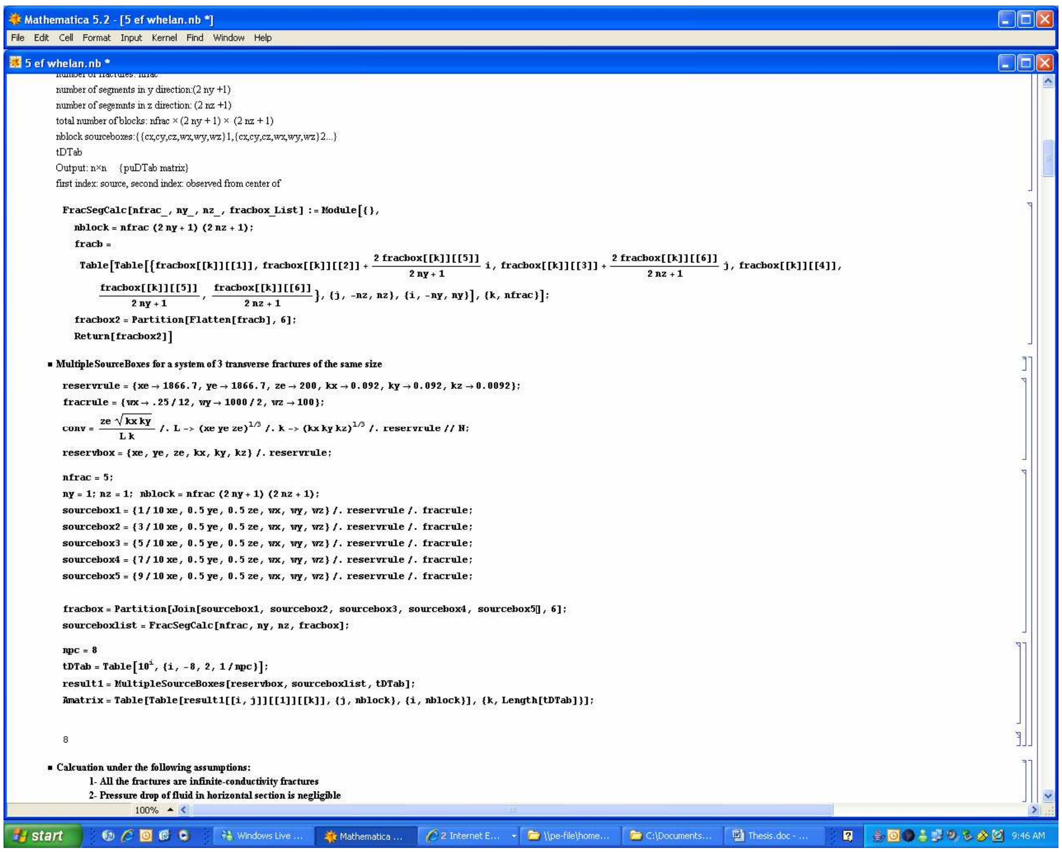
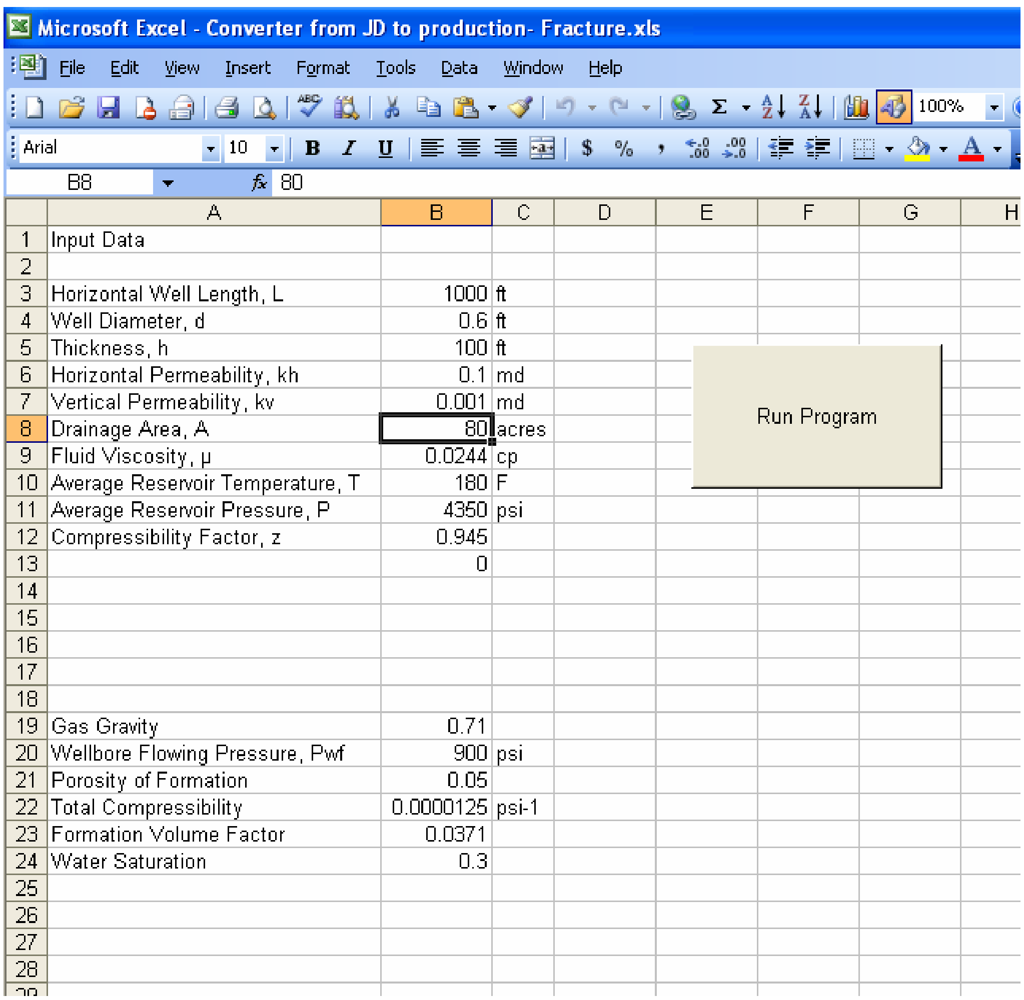


Fig. A.2 Display for 5 fracture setup

After all the modifications are done to specify what the user wants, the program is then run. To do that, the user must click on Kernel on the toolbar, and then run entire notebook. The result is going to be displayed in an Excel spreadsheet that is place on the desktop under the folder Runs. This excel spreadsheet displays 3 columns, The first column displays the dimensionless time, T_D, the second displays J_D, and the third the fraction of the flow that is placed within each fracture. This last column is important to detect errors. If the fractures are placed equally spaced and symmetrically in the reservoir the production fraction for each should be the same.

APPENDIX B
CONVERTER SPREADSHEET

The next step is to use the converter program. This program is used to convert the data from dimensionless variables to real time and production, in days and millions of standard cubic feet per day. The first step of this program is to fill the information on the Sheet1 spreadsheet. Fig. B.1. The reservoir and fluid data, in this panel have to be filled in order for the program to perform the conversion.



	A	B	C
1	Input Data		
3	Horizontal Well Length, L	1000	ft
4	Well Diameter, d	0.6	ft
5	Thickness, h	100	ft
6	Horizontal Permeability, kh	0.1	md
7	Vertical Permeability, kv	0.001	md
8	Drainage Area, A	80	acres
9	Fluid Viscosity, µ	0.0244	cp
10	Average Reservoir Temperature, T	180	F
11	Average Reservoir Pressure, P	4350	psi
12	Compressibility Factor, z	0.945	
13		0	
19	Gas Gravity	0.71	
20	Wellbore Flowing Pressure, Pwf	900	psi
21	Porosity of Formation	0.05	
22	Total Compressibility	0.0000125	psi-1
23	Formation Volume Factor	0.0371	
24	Water Saturation	0.3	

Fig. B.1 Display of sheet1 on the converter program

Next, the user has to switch to Sheet2, and paste the T_D and J_D information on the first two columns (colored yellow) as shown in Fig. B.2. After clicking on the "Run Program" button, the results will be displayed on the next two columns (colored blue). The user can clear the cells to run the program one more time, by clicking on the "Clear Cells" button. From the Time and Production data, a graph can be created with the preferences of the user.

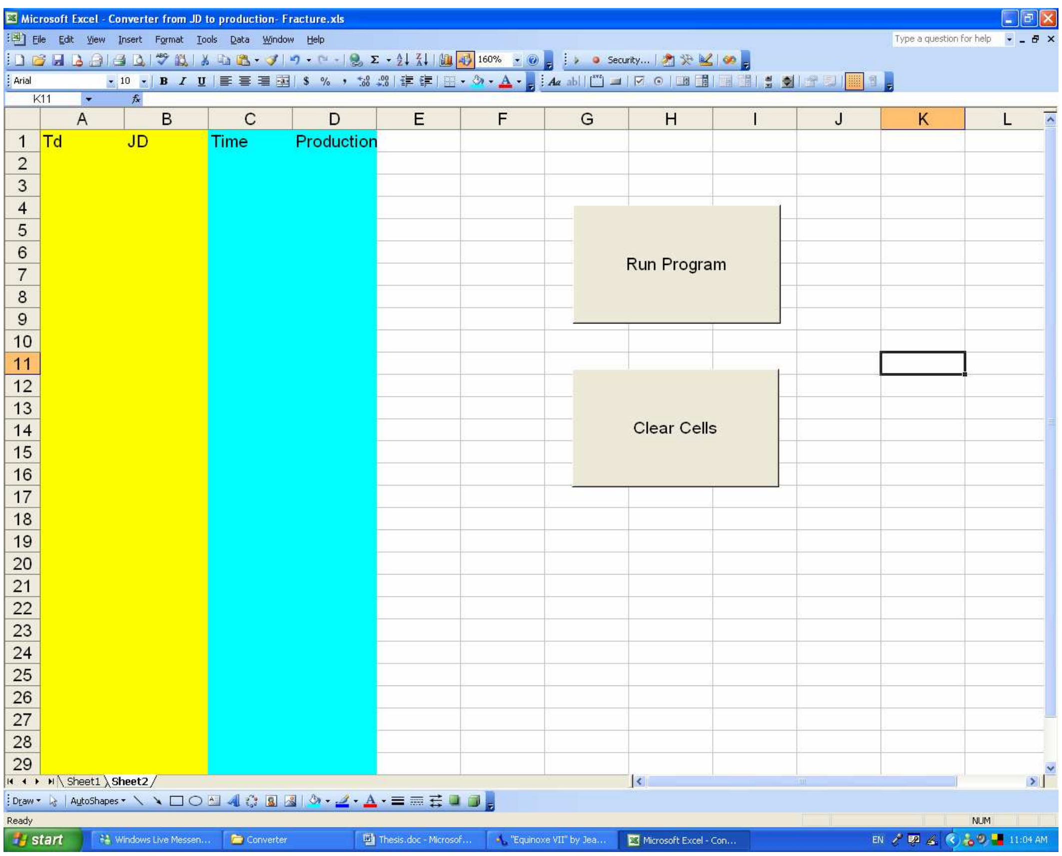


Fig. B.2 Display of sheet2 on converter program

This program works by first reading all the variables in Sheet1 and also Sheet2. A variable of reference dimension (x_{ref}) and reference permeability (k_{ref}) are defined as:

$$x_{ref} = \sqrt{x_{res} \cdot y_{res} \cdot z_{res}} \qquad \text{(B.1)}$$

$$k_{ref} = x_{ref}^{\ 2} \cdot \frac{k_x \cdot k_y \cdot k_z}{\left(x_{res} \cdot y_{res} \cdot z_{res}\right)^{\frac{1}{3}}} \tag{B.2}$$

These two variables are used in converting T_D and J_D. These variables (T_D and J_D) are read down the lines from the spreadsheet and then plugged in to the following equations to be converted:

$$t = T_D \cdot \frac{\mu \cdot c_t \cdot \phi \cdot x_{ref}^{\ 2}}{0.00633 \cdot k_h} \tag{B.3}$$

$$q = \frac{\left(\overline{p}^2 - p_{wf}^{\ 2}\right) \cdot k_h \cdot h}{1632 \cdot \mu \cdot z_i \cdot \overline{T}} \cdot J_D \tag{B.4}$$

This process is repeated until T_D equals 1 is encountered. This point indicated that the boundaries were felt by the pressure; meaning that the transient time is over. J_D from that point is stabilized and the equation from flow rate is modified on the following fashion.

$$q = \frac{\left(\overline{p}^2 - p_{wf}^{\ 2}\right) \cdot k_h \cdot h}{1424 \cdot \mu \cdot z \cdot \overline{T}} \cdot J_D \tag{B.5}$$

After this first point, the new z-factor is calculated by correlations and the cumulative production is also calculated. These two new variables are used to calculate the pressure drop in the reservoir by using material balance.

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